Commonwealth of Kentucky
Division for Air Quality

RESPONSE TO COMMENTS

ON THE TITLE V PERMIT NO: V-02-043 REVISION 2
Louisville Gas and Electric Company
P.O. Box 32010, Louisville, Kentucky, 40232
November 17, 2005

BEN MARKIN, REVIEWER

SOURCE I.D. #:	021-223-00002
SOURCE A.I. #:	4054
ACTIVITY #:	APE 20040003

SOURCE DESCRIPTION:

Louisville Gas and Electric Company (LG&E), as operator, submitted an air permit application dated December 01, 2004, to construct a new 750 megawatt (MW) net nominal generating unit that will utilize supercritical pulverized coal (SPC) technology at its existing Trimble County Generating Station located west of Bedford in Trimble County, Kentucky. The new SPC boiler will be equipped with Selective Catalytic Reduction (SCR), Pulse Jet Fabric Filters (PJFF), a Wet Flue Gas Desulfurization (WFGD) System, and a Wet Electrostatic Precipitator (WESP). It will exhaust through two exhaust flues located within an existing common chimney and will be equipped for ASTM Grade No. 2-D S15 (sulfur content ≤ 15 ppm) fuel oil for start-up and stabilization. Existing equipment at the Trimble County Generating Station includes the following: a 500 MW (nominal rated capacity) pulverized coal generating unit (Emissions Unit 1), six 160 MW (nominal rated capacity) simple cycle natural gas combustion turbines (Emissions Units 25-30), a natural draft cooling tower, coal/limestone/ash/gypsum material handling equipment, three auxiliary boilers, an emergency diesel generator, and fuel oil storage tanks. The natural draft cooling tower, coal/limestone/ash/gypsum material handling equipment, and fuel oil storage tanks will have increased utilization when the new SPC boiler becomes operational. The new facilities that will be constructed as part of this proposed project will include the SPC boiler (Emissions Unit 31), a linear mechanical draft cooling tower (LMDCT) for Emissions Unit 1, a coal blending facility, dust collectors and dust suppression equipment on material handling operations, an ash barge loading system/fly ash silos, an auxiliary steam boiler, a backup diesel generator, and an emergency diesel fire water pump engine. The seven existing combustion units (Emissions Unit 1 and Emissions Units 25 -30) are not part of the proposed major modification, and have previously gone through Prevention of Significant Deterioration (PSD) review. The proposed project constitutes a major modification of a major stationary source as defined in 401 KAR 51:017, Prevention of Significant Deterioration of Air Quality. The proposed project will result in a significant net emissions increase, as defined in 401 KAR 51:001 Section 1(146), of the following regulated air pollutants: particulate matter (PM & PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), fluorides, and sulfuric acid (H_2SO_4) mist. The proposed project is not subject to PSD review for nitrogen oxides (NO_x) and sulfur dioxide (SO_2) based on contemporaneous and creditable emission reductions of NO_x and SO_2 from the existing PC boiler (Emissions Unit 1). The source has chosen a twenty four (24) month baseline of actual SO2 emission for Unit 1 for the period of January 1, 2001 to December 31, 2002. For NOx, the baseline was January 1, 2000 to December 31, 2001. The emissions reductions from Emissions Unit 1 will be such that there will be no significant net emissions increase of NO_x and SO_2 thus removing these two pollutants from this PSD review. In addition, the project will not emit lead above the significant emission rate for lead of 0.6 tons per year (tpy), set forth in 401 KAR 51:001 Section 1(221) and 40 CFR 51. Emissions from the project of hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds will also be below significant emission levels and are therefore not subject to PSD review.

The Trimble County Generating Station is located in a county classified as “attainment” or “unclassified” for each of the PSD applicable pollutants pursuant to 401 KAR 51:010, Attainment Status Designations. The Trimble County Generating Station is an existing major stationary source under the PSD regulations as defined in 401 KAR 51:001, Section 1(120). The proposed project meets the definition of a major modification and is subject to evaluation and review under the provisions of the PSD regulation for PM, PM_{10} & $PM_{2.5}$, CO, VOC, fluorides, and H_2SO_4 mist. A PSD review involves the following six requirements:

1. Demonstration of the application of Best Available Control Technology (BACT).
2. Demonstration of compliance with each applicable emission limitation under 401 KAR Chapters 50 to 65 and each applicable emissions standard and standard of performance under 40 CFR Parts 60, 61, and 63.
3. Air quality impact analysis.
4. Class I area impact analysis.
5. Projected growth analysis.
6. Analysis of the effects on soils, vegetation and visibility.

Furthermore, the source will also be subject to Title V, Title IV Phase II Acid Rain and NOx SIP Call permitting. The Title V permitting procedures are contained in 401 KAR 52:020. The Title IV permitting procedures are within 401 KAR 52:020, Permits, 401 KAR 52:060, Acid Rain Permit, 40 CFR Part 72, 40 CFR Part 76 and 40 CFR 97. NOx SIP Call permitting procedures are within 401 KAR 51:160 and 40 CFR 96.. This Statement of Basis addresses the proposed conditions of the PSD/Title V permit and the Title IV Phase II Acid Rain permit. This review demonstrates that all regulatory requirements will be met and includes a permit that would establish the enforceability of all applicable requirements. This review is to ensure that the source shall be considered in compliance with all applicable requirements, as of the date of permit issuance for the applicable requirements that are specifically identified in the permit, and specifically identified requirements that have been determined to not be applicable to the source.

Louisville Gas & Electric Company submitted a minor revision application to the Division on April 29, 2005 for a voluntary creditable decrease in emissions for the permitted Unit 1, a 5,333 mmBtu/hr, pulverized coal-fired boiler in operation in 1990. The creditable decrease in emissions will be 3,225 tons per year of sulfur dioxide. This permit will limit the twelve (12) month rolling total on the unit sulfur dioxide (SO_2) on the unit to 4,822 tons per year. The credible reduction is requested by the facility to net against future potential increase from the construction of the additional utility boiler (TC2). The practically enforceable creditable reduction is being done in accordance with new source review (NSR) rules. [401 KAR 51:001 and 401 KAR 51:017] Compliance with the emissions limit shall be demonstrated using continuous emission monitoring equipment which measures the emissions hourly and procedures required by 401 KAR 52:060 (acid rain program). The sulfur dioxide limit shall become effective January 1, 2006. A previous minor permit revision limited nitrogen oxide emissions from Unit 1 to 5,556 tons per year, a credible decrease of 1,485 tons per year. That limit was effective January 1, 2005.

PUBLIC AND U.S. EPA REVIEW:

On July 6, 2005, the public notice on availability of the draft permit and supporting material for comments by persons affected by the plant was published in *The Courier journal and Trimble Banner* in Louisville and Bedford, Kentucky. The public comment period expired 30 days from the date of publication.

Comments were received from the U.S. EPA Region 4, the Sierra Club-Mid West Office, Valley Watch, and Save the Valley on August 4, 2005, August 8, 2005 August 9, 2005 and August 10, 2005 respectively. Attachment A to this document lists the comments received and the Division's response to each comment. Minor changes were made to the permit as a result of the comments received, however, in no case were any emissions standards, or any monitoring, recordkeeping or reporting requirements relaxed. Please see Attachment A for a detailed explanation of the changes made to the permit. The U.S. EPA has 45 days to comment on this proposed Title V permit.

ATTACHMENT A

Response to Comments

Comments on the Louisville Gas & Electric Company's Trimble Co. Generating Station Draft Title V Air Quality Permit submitted by Gregg Worley on behalf of the U.S. EPA Region 4, Bruce Niles on behalf of Sierra Club Midwest Office, John Blair on behalf Valley Watch, Richard Hill on behalf of Save the Valley

U.S. EPA Region 4-PSD Comments:

A. Netting Analysis

1) Much of the permit is structured on the fact that LG&E is netting out of PSD review for SO_2 and NO_x. The permit application and Statement of Basis do not themselves provide netting calculations showing exactly how baseline actual emissions for SO_2 and NO_x from Unit 1 were derived. We have reviewed two additional documents that we understand are in the public record to provide netting information. One document is dated April 29, 2005, and shows actual monthly SO_2 emissions for Unit 1 covering the period January 2001 to December 2002. These emissions were used to calculate baseline SO_2 actual emissions for netting purposes. The other document is dated November 22, 2004, and purportedly provides documentation for NO_x netting purposes. However, this document does not list actual monthly NO_x emissions used to derive baseline actual emissions. It is critical that the permit record clearly support the determination made by KDAQ

Division Response:

The Division included the information regarding monthly NOx emission used to derive baseline actual emissions in the public record on file at the County Clerk's Office and the Division central file.

2) For an emissions decrease to be creditable in a netting analysis, it must have approximately the same qualitative significance for public health and welfare as that attributed to the increase. KDAQ should verify that the decreases in SO_2 and NO_x emissions from Unit 1 meet the same qualitative significance criterion. This assessment needs to take into account the dispersion characteristics of Unit 1 in comparison with the dispersion characteristics of the proposed new NO_x and SO_2 emissions units (primarily the new pulverized coal boiler and the new auxiliary boiler).

Division Response:

The Division has researched this matter for further guidance, and has found little in the regulatory record, other than a single mention in a 1992 letter concerning Cyprus Northshore Mining Corporation. The Division was unable to find any other instance in the regulatory record. There is some guidance in the draft PSD Manual of 1990. The Division has confirmed that this netting will not lead to a potential violation of any NAAQS, which appears to be the main gist of the 1992 letter.

> From the Draft 1990 PSD Manual
> *Where there is reason to believe that the reduction in ambient concentrations from the decrease will not be sufficient to prevent the proposed emissions increase from causing or contributing to a violation of any NAAQS or PSD increment, this provision requires an applicant to demonstrate that the proposed netting transaction (despite the absence of a significant net increase in emissions) will not cause or contribute to such a violation (see 54 FR 27298)*

The applicant has supplied appropriate Class II modeling to ensure that the NAAQS are protected. The Division's understanding is that NAAQS' are presumptively protective of human health. Also see response to comment 31 below.

3) In the final Statement of Basis, we recommend that KDAQ identify the specific contemporaneous period dates used for the NO_x and SO_2 netting assessments and the specific past consecutive 24-month periods used to calculate baseline emissions.

Division Response:

The Division has made the changes to the Statement of Basis.

B. Proposed New Unit 2 Pulverized Coal Boiler (Emissions Unit 31)

Emissions Limits

4) The draft permit 30-day averaging periods for VOC, sulfuric acid mist, and fluoride emissions in conditions B.2.i), j), and k) are not consistent with the compliance determination methods for these pollutants.

Division Response:

The Division concurs with the comment and has revised the permit to include a three (3) hour rolling average, which coincides with three one hour performance tests, and is consistent with the compliance determination method for the pollutant.

5) In the draft permit for the proposed Unit 2 pulverized coal boiler (Emissions Unit 31), KDAQ specifies a CO BACT limit of 0.10 lb/MMBtu on a 30-day rolling average basis. An emissions limit is also needed for consistency with the emissions rate used for modeling purposes. This limit should be on a pounds per hour basis with an averaging period not to exceed 3 hours.

Division Response:

In addition to the BACT limit for CO, the Division concurs that an emission rate should be set to ensure protection of the NAAQS. The Division has revised the permit to include a three (3) hour rolling average limit of 0.5lb/ mmBtuTU . The permits analysis of the SAI and SIL have been revised to reflect this short-term limit which is supported by modeling submitted by the applicant. The Division believes the CO CEM's will address the pounds per hour issue, which is the compliance determination method

6) The final permit should specify emissions limits for PM/PM_{10}, CO, and VOC in pounds per hour as well as in pounds per million Btu.

Division Response:

The Division considers the lb/mmBtu limit in the permit is adequate to demonstrate compliance with existing regulations. Though the PM CEM's is not in operation, however upon completion of the project the CEM's will be sufficient to provide information in pounds per hour. The Division is aware of the recent proposed changes in the federal PSD regulations. To aid in future review, the statement of basis will include a summary of the permitted emissions. The Division will consult with U.S. EPA to address implementation when and if the proposed regulatory changes are made.

<u>Compliance Monitoring</u>

7) The PM/PM_{10} emissions limits for Unit 2 are for both filterable and condensable particles. The compliance monitoring method for these limits appears to be solely use of a PM CEMS. We recommend that KDAQ check to make sure that available PM CEMS can detect condensable as well as filterable particles. If needed, KDAQ could require a supplemental measurement method for condensable in addition to a PM CEMS.

Division Response:

At this time, the applicant has not determined which available CEM monitoring technology will be used. The assumption of this permit is that the final approved design will meet performance specification and this permit requirement to assure compliance with the BACT limit. The Division acknowledges there is some technical uncertainty about this issue at this time, but since the final choice for a PM CEM technology is several years away, we are issuing this permit based on the assumption that an appropriate monitor will be available that meets all of the state and federal requirements. In the event that the applicant later determines that a monitor that meets the requirements for PS-11 for a particulate CEM cannot appropriately monitor condensable matter; then the Division may reopen this permit to revise the procedures for CAM and compliance monitoring. Additionally, annual PM/PM_{10} *performance tests will verify condensable particulate emission levels.*

8) KDAQ is requiring that compliance assurance monitoring for sulfuric acid mist shall be the use of an SO_2 CEM with an indicator range established by initial source testing. Although we are not discounting this approach, we note that a wet FGD scrubber (the Unit 2 {sic Unit 31} SO_2 control device) is not highly effective in controlling sulfuric acid mist emissions. Therefore, it may not be possible to establish a close correlation between SO_2 and sulfuric

acid mist emissions. We recommend that KDAQ consider supplemental monitoring for sulfuric acid mist based on WESP operating parameters such as liquid flow rate, voltage, and/or other operating parameters. We will provide suggested monitoring requirements when we comment on the proposed title V permit.

Division Response:

The Division concurs with the comment and has modified the CAM requirements in the statement of basis and the permit to include the flow rate, voltage, and /or other operating parameters for the WESP.

PM Best Available Control Technology

9) In support of the proposed PM/PM_{10} BACT limit of 0.018 lb/MMBtu (a limit accepted by KDAQ), LG&E cites similar BACT limits in recent Santee Cooper (South Carolina) and Longview (West Virginia) permits. The Santee Cooper permit limit (which includes condensable PM) is based on use of a dry ESP only and not a combination of PJFF and WESP as proposed for Unit 2. Although we agree that the combination of PJFF and WESP represents an appropriate BACT collection method, we would expect that this combination would be able to achieve lower emissions than a dry ESP alone.

Division Response:

The Division believes that the PM/PM_{10} BACT analysis and limit were properly conducted and stands by its conclusions. BACT limit for total PM are consistently being set at the 0.018 lb/mmBtu level by a variety of permitting agencies, and this is appropriate considering the variety of concerns on compliance methods. The combined use of a PJFF and WESP will provide a technology demonstration that subsequently may provide the basis for lower BACT determinations in the future.

Startup and Shutdown

10) KDAQ specifies in permit condition B. 2.p) for the new pulverized coal boiler (Emissions Unit 31) that “the owner or operator shall utilize good work and maintenance practices and manufacturer’s recommendations to minimize emissions” during startup and shutdown events. In addition to this good practices requirement, we further recommend that KDAQ require the owner/operator to develop a startup/shutdown plan.

Division Response:

The Division acknowledges the comment and has added start-up and shut down language to the permit. 'The permittee shall submit a startup and shut down plan implementing the requirements of this permit and 401 KAR 50:055 during such periods. The plan must be submitted no later than 90 days prior to the startup of the boiler for the Division's approval. The startup/shutdown plan will be accessible for public review at the Division's central office and the regional office.

11) U.S. EPA comment letter did not include a comment numbered "11".

Fuel Oil Specification

12) The final permit should include an enforceable condition specifying that the only fuel used for startup and shutdown shall be fuel oil meeting the specifications of ASTM Grade No.2-D S15. Furthermore, if it is KDAQ's intent to establish maximum fuel oil sulfur content, the maximum content should be specified in the permit in addition to specification of the ASTM grade. (Also see Item 15 below.)

Division Response:

The Division has added the enforceable fuel usage for startup and stabilization language to the permit.

Final Design Information

13) LG&E states the following on page C-3 of the permit application: "Decisions on the boiler design, such as tangentially or opposed wall firing, have not been finalized." We recommend that you add a permit condition requiring that final design information be provided when LG&E makes its selections.

Division Response:

The Division concurs and has added a language in the permit requesting the permittee to provide the Division the final design information. The design plan will be accessible for public review at the Division's central office and the regional office upon receipt.

C. Existing Unit 1 Pulverized Coal Boiler (Emissions Unit 01)

14) The final permit for the existing Unit 1 pulverized coal boiler should contain startup and shutdown conditions equivalent to those for the proposed Unit 2 pulverized coal boiler. Unit 1 permit conditions should specify that emissions during startup and shutdown shall be included in determining compliance with tons-per-year emissions limits. This is consistent with Kentucky rules in 401 KAR 51.001 Section 1.(202)(b)1.b. which requires consideration of startup and shutdown emissions when calculating projected actual emissions.

Division Response:

Startup and shutdown emissions from Unit 1 are included when determining compliance with tons per year emission limits that apply to Unit #1. Unit #1 is not undergoing a BACT review. At the time that Unit #1 was subject to a BACT review, it was determined that, startup and shutdown requirments were addressed by 401 KAR 50:055. The Division believes adequate monitoring is in place to assess Unit 1 emissions.

D. Proposed New Auxiliary Boiler

15) Permit condition B.2.c) for the new oil-fired auxiliary steam boiler (Emissions Unit 32) restricts sulfur dioxide emissions by requiring that "... the fuel oil used must meet the sulfur content standards in ASTM Grade No. 2-D S15." If it is KDAQ's intent to establish maximum fuel oil sulfur content, this maximum content should be specified in the permit. A possible re-wording of the permit condition is as follows: "...the fuel oil used must meet the sulfur content standards in ASTM Grade No. 2-D S15 and can not exceed a sulfur content of 15 ppm." A value of 15 ppm is the current maximum sulfur content specified in ASTM Grade No. 2-D S15.

Division Response:

The Division concurs and the suggested additional language has been added to the permit.

E. Particulate Matter Nonattainment Areas

16) Neither the permit application nor KDAQ's Statement of Basis acknowledges the proximity of the project site to the nearest $PM_{2.5}$ nonattainment areas - the Louisville nonattainment area and the Cincinnati nonattainment area (which includes three Kentucky counties). KDAQ should acknowledge these areas and provide a qualitative or quantitative explanation of why the proposed project will not interfere with achieving compliance in these areas.

Division Response:

On November1, 2005, U.S.EPA published in the federal register implementation guidance for the $PM_{2.5}$ NAAQS or NSR programs. KDAQ has evaluated its options and will develop appropriate methods/regulations to ensure compliance will be achieved. In the interim, the Division has verified that the PM_{10} NAAQS (the approved surrogate for $PM_{2.5}$) is being protected. LG&E's modeling was based on direct emissions of filterable and condensable PM emissions and is not significant at the point of maximum project impact both for the annual and the 24-hour periods. Impacts further away from the facility, at nearby $PM_{2.5}$ nonattainment areas should be lower.

U.S. EPA Region 4-Part 70 Comments

Comment

17) For Unit 01, under Applicable Regulations, the requirements of acid rain (i.e., 40 CFR Parts 72, 73, 75, and 76) should be listed.

Division Response:

The Division does not concur. U.S. EPA has made multiple comments on the existing unit #1 that are outside of the significant revision permit process. Public notice was given under 401 KAR 52:100 Section 4, that stated that this permit action was "Concerning the Construction and Operation of a new coal fired electrical generating unit". With the concurrence of the source we are including the majority of the requested changes regarding regulatory citations in this permit. Additionally, the existing permit always contained requirements of the acid rain program, but in a separate section J of the permit.

Comment

18) For Unit 1, under Emission Limitations, the NO_x limit of 0.45 lb/mmBtu (pursuant to 40 CFR Part 76) needs to be included. This would reflect what is included in the respective acid rain permit (Section J).

Division Response:

Please refer to comment 17. The addition has been made to the permit under the emission limitations.

Comment

19) For Unit 31, under Applicable Regulations, the requirements of 40 CFR Part 72 should be included.

Division Response:

Although this requirement was addressed in Section J of the permit, the additions also have been made to Section B of the permit.

Comment

20) For Unit 31, under Emission Limitations, it appears that the SO_2 and NO_x limits pursuant to 401 KAR 59:016 have been inadvertently omitted. The statement of basis shows applicable limits (on a lb/mmBTU basis that vary with respect to percent reduction) that are not reflected in the permit.

Division Response:

Compliance with the proposed NSPS limits ensures compliance with the 401 KAR 59:016. The permit has been changed to the requirements of 401 KAR 59:016.

Comment

21) For Unit 31, under Specific Monitoring Requirements, the appropriate references to 40 CFR Part 75 need to be added to the conditions requiring the use of CEMS to monitor SO_2 and NO_x emissions.

Division Response:

The omissions have been added to the permit.

Comment

22) The statement of basis erroneously states that Unit 31 is subject to 40 CFR Part 76; part 76 applies to existing rather than new units. Furthermore, for completeness, the statement of basis should include part 72 as an applicable requirement regarding Unit 31.

Division Response:

The Division acknowledges the comment and has made the editorial changes to the permit and the statement of basis.

Comment

23) With respect to specific applicable acid rain requirements, the citations of authority given must exhibit a level of detail that is adequate (i.e., they must be cited "down" to that subsection which it is clear as to what applies). For instance, citing "40 CFR Part 75" as the authority for requiring CEMS is inadequate since the monitoring requirements of part 75 are dependent upon a number of variables (e.g., the type of fuel being combusted). It is acceptable, however, to cite "40 CFR Part 75" as being applicable under the more general Applicable Regulations section.

Division Response:

The Division will work with U.S. EPA to expand this standard language on future permit renewals. This permit condition is consistent with the language that was present when the source wide Title V was issued in June 2003.

Comment

24) With respect to CAM, it would be more appropriate to monitor parameters of the immediate (or applicable) control device. For instance, regarding sulfuric acid mist emissions, CAM should specify parameters of the wet electrostatic precipitator (WESP) to be monitored. A review draft section (Appendix B.3) of EPA's CAM Technical Guidance Document lists some of the performance indicators related to WESPs, such as secondary current (which may identify inoperative/malfunctioning fields) and inlet water flow rate (which may indicate plugging).

Division Response:

See response to comment #8 under U.S. EPA

<u>Sierra Club, Valley Watch and Save the Valley-Comments</u>

25)-**I. SUMMARY**

Our organizations respectively request that the comment period for the proposed operating and construction permit for a new electrical generating unit at Louisville Gas and Electric's Trimble County power plant be extended for another sixty days. If the public comment period is not extended we request that the permit is denied because, as detailed below, it fails to meet the minimum health protection requirements of Kentucky and federal law.

Division Response:

The Division does not concur. The provision and time frames for public comments are specified in 401 KAR 52:100, and 401 KAR 51:017. These regulations were adhered to. Additionally, the permit will comply with Kentucky and Federal regulation designed to protect public health. Please also see response to II, below.

26)-**II. SHORTCOMINGS IN THE PUBLIC PROCESS**
The agency received this application on December 1, 2004. Approximately eight months later, after reviewing the application and conducting its own analysis, the agency issued a draft permit. The draft permit was announced in early July. We could not locate any information indicating when the agency announced the draft permit and when the comment period formally commenced or will end. The date triggering commencement of the public notice is not listed on the website. The website states: "[t]o be considered, any written comments must be postmarked within 30 days following the date of publication of this notice in the local paper." www.air.ky.gov/homepage_repository/Public+Hearings.htm. The agency's website does not state which newspaper it is referring to and whether any notice was ever published, and if so, on what date. That is not adequate notice. The agency unfairly denied multiple requests for an extension of the public comment period. Following announcement of the draft permit representatives of our organizations requested an extension in order to receive, to review, and to comment on the administrative record relating to this project. These requests were summarily denied, except that the agency granted an additional two days for filing written comments. This unwillingness to grant an extension is highly prejudicial and unprecedented. We are unaware of any other state agency that has refused to grant a meaningful extension of time for the public to review and comment on a draft permit for a coal-fired power plant. For example, Illinois recently granted citizens an additional ninety days to comment on the proposed Peabody Energy Prairie State project. The magnitude of the Trimble project and the voluminous permit information all warrant careful consideration. Absent more time these comments do not reflect a review of the complete administrative record because there simply was inadequate time to conduct such a review. In addition, our expert Dr. Fox did travel to Kentucky to review the project files, and key information appears to be missing from the agency files. The files that we reviewed did not contain the file for the SO_2 reduction nor any detailed emission calculations that support the netting analysis for either NO_x or SO_2. This problem cannot be resolved within the timelines established by the agency. We again urge your agency to allow meaningful public comment and extend the comment deadline for another sixty days. This will afford us with the opportunity to work with the agency to identify the information that appears to be missing from the publicly accessible files and then sufficient time to review the complete file and prepare more detailed comments.

Division Response:

The Division met and exceeded every regulatory requirement for public notice. The procedures for public notice are present in 401 KAR 52:100 and 401 KAR 51:017. "The cabinet shall provide public notice of a comment period and any scheduled public hearing by prominent publication in the newspaper having the largest general circulation in the area where a facility is applying for a permit". This obligation was met by the publication of a public notice in the Trimble County Banner. In addition, going beyond the regulatory requirements a notice was placed in the Louisville Courier Journal. Additionally, the Division for Air Quality places courtesy notices on its webpage. The commenter finds fault with issues of timing with the notice on the webpage. Kentucky is placing *these notices on its webpage as courtesy to the public as an additional mechanism for dissemination of information the public. The maintenance of such a web site is required neither in regulation nor statutes and is, in fact, not common practice among many agencies.*

The Division will take under advisement suggestions to improve its public out reach procedures. We will investigate if it is possible to include the paper of publication in its future web notices. The Division is committed to improve public outreach and notification.

There also seems to be some confusion about the completeness of the public record for this permit. As the commenter has pointed out, the source used netting procedures. In simplest terms netting is an analysis of looking at contemporaneous emission decreases and increases. Some of the emission decreases that the applicant relied upon were covered in previous permit applications. Appropriate supporting materials on reductions were provided to the public through the air permit application document, the Statement of Basis netting discussion, and minor permit revision applications supporting the creditable emission decreases that were submitted to KDAQ on November 22, 2004 and April 29, 2005.

We have reviewed all possible guidance and discussed with U.S. EPA Region 04 and out sister agencies to confirm that this approach is consistent and common when dealing with netting applications.

Lastly, Kentucky is aware of the project in Illinois. That agency extended its permit period based on Illinois state authority. Kentucky does not see how that decision is germane to a Kentucky permit.

27)-**III. NEW SOURCE REVIEW IS TRIGGERED FOR NO_x AND SO_2**

Trimble proposes to net out of New Source Review ("NSR") for NO_x and SO_2 by obtaining voluntary creditable emission reductions from Trimble Unit 1 under 401 KAR 51:001 and 401 KAR 51:017. SOB at 3-6. Based on our analysis outlined below, the netting analysis overestimates the NO_x and SO_2 emission reductions. Applying the proper calculations the net increase in NO_x and SO_2 emissions due to the project exceed the significance thresholds of 40 ton/yr for NO_x and SO_2, and thereby PSD review is triggered.

Division Response:

The Division does not concur, and believes the commenter is misinterpreting the provision of the regulations for reasons further discussed below.

28)-**A. The Netting Calculation Used the Wrong Baseline**

The netting calculation used the wrong baseline in calculating creditable emission reductions. The Division proposes to allow Trimble to net out of PSD review for NO_x and SO_2 by generating a net reduction in NO_x and SO_2 at existing Unit 1. The Division used the calculation procedure for the actual-to-projected actual applicability test in the recently revised state NSR rule, 401 KAR 51:017, Sec. 1(4)(a)(1), rather than the procedure for netting in the recently revised NSR rule 401 KAR 51:001, Sec. 1(146). These state rules were revised to incorporate the December 2002 revisions to federal regulations at 40 C.F.R. § 52.21. 67 Fed. Reg. 80,186 (Dec. 31, 2002). These procedures are distinguishable. The EPA explained in the preamble to Federal Register that it was not revising the method used to perform netting and that the new actual-to-projected actual applicability test does not apply to netting. *Id.* at 80,203-80,204. The Division erred by applying the actual-to-projected-actual applicability test to netting. The "creditable emission reductions" from Unit 1 were determined as the difference between Unit 1's pre-change baseline actual emissions ("BAE") and post change enforceable emission limits. The BAE was calculated as the emission rate, in tons per year, based on the actual emissions determined over a consecutive 24-month period during the 60-month period preceding the date on which an enforceable permit limit for SO_2 and NO_x is taken. SOB at 5. This is the wrong baseline. "Actual emissions" should have been used, rather than "baseline actual emissions." The claimed NO_x reduction, which became effective January 1, 2005 (SOB at 3), was based on emissions that occurred in 2000-2001. The actual NO_x emissions immediately prior to the reduction were much lower. Similarly, the claimed SO_2 reduction, which becomes effective January 1, 2006 (SOB at 3), was based on emissions that occurred in 2001-2002. The actual SO_2 emissions immediately prior to the reduction were much lower. If actual emissions are used to calculate the creditable emission reduction, the net increase in NO_x and SO_2 emissions from Trimble Unit 2 exceed the PSD significance threshold of 40 ton/yr, triggering PSD review. This is true under both the new state NSR rule and the SIP-approved NSR rule for different reasons. 401 KAR 51:017.

1. State NSR Rule

Under the new state NSR rule, NSR is triggered if a project "causes a significant emissions increase and a significant net emissions increase." 401 KAR 51:017, Sec. 1(4). The "baseline actual emissions" relied on by the Division to determine if a "net emission increase" had occurred is only used in the first prong of this test, to determine if a "significant emissions increase" has occurred when using the "actual-to-projected actual applicability test". 401 KAR 51:017, Sec. 1(4)(a)(1). It is not used to determine if a significant net emissions increase has occurred. The second prong of this test calculates "net emission increase" pursuant to 401 KAR 51:001, Sec. 1(146). The "net emission increase" calculation, which the Division relied on to conclude Trimble netted out of NSR, is based on "actual emissions" not "baseline actual emissions." This subsection states that "actual emissions" as defined in 401 KAR 51:001, Sec. 1(2) does not apply to the term as used in KAR 51:001, Sec. 1(146). 401 KAR 51:001, Sec. 1(146)(h). The term "actual emissions" as used to determine a "net emission increase" is not defined anywhere else in the state version of 401 KAR 51:001 or 401 KAR 51:017. Thus, the plain language definition of the term "actual emissions" applies. "Actual" used as an adjective means "being, existing, or acting at the present moment; current" (Houghton Mifflin), "presently existing in fact and not merely potential or possible," or "being or existing at the present moment," (WordNet).[2]

The NO_x and SO_2 emission reductions at Unit 1 claimed to offset the emission increases at new Unit 2 were not based on "actual" emissions within the plain meaning of this term. As discussed below, they were based on emissions that occurred 4 years before the reductions were enforceable. The "actual" emissions at the time of the claimed emission reductions were much lower than the historic emissions used to generate the credit. Thus, the emission reduction credit should have been smaller than claimed, resulting in a significant net emission increase of NO_x and SO_2.

Division Response:

The Division does not concur with this interpretation of Kentucky's regulation. The Division has acted consistently within the federal program and its own state regulation. Under 401 KAR 51:017 Section 1(4), a project is a major modification only if it causes a significant emission increase and a significant net emission increase. The determination whether a project has resulted in a significant net emission increase is made pursuant to 401 KAR 51:001 Section 1(146), which specifies that "the *term actual emissions as defined in subsection (2) of [401 KAR 51:001 Section 1] does not apply in determining creditable increases and decreases." See 401 KAR 51:017 Section 1(4)(b). Thus, the definition of "actual emissions" under 401 KAR 51:001 Section 1(2) does not apply to the determination of baseline emissions for the purpose of calculating the net emission increase associated with a project. Further, the definition of "baseline actual emissions" at 401 KAR 51:001 Section 1(2) applies to the determination of creditable emissions decreases from emission units. For an existing electric utility steam generating unit, the "baseline actual emissions" is defined as the "rate of emissions in tons per year, of a regulated NSR pollutant that...the unit actually emitted during any consecutive twenty-four (24) month period selected by the owner or operator within the five (5) year period immediately preceding the date the owner or operator begins actual construction of the project." The five-year look-back period therefore was properly applied in the netting analysis.*

29)-2. SIP-Approved NSR Rule

The Kentucky State Implementation Plan ("SIP") also includes an NSR regulation that is federally enforceable. To the extent there is any conflict between this SIP approved regulation and the new state regulation, the SIP approved regulation is considered federal law and therefore trumps any conflicts with the new state regulation. The following comment is based on the SIP NSR rule posted on EPA Region 4's website.[3] To the best of our knowledge, this SIP NSR rule has not been modified and thus applies to Trimble Unit 2.

Under this SIP rule, NSR is triggered for major modifications that construct after September 22, 1982, emit a regulated pollutant, and are constructed in an attainment area. SIP 401 KAR 51:017, Sec. 2. A project is a major modification if it results in a significant net emission increase. SIP 401 KAR 51:017, Sec. 1(23). A significant net emission increase is defined nearly identical to State 401 KAR 51:017, Sec. 1(146), except the definition of "actual" is different. SIP 401 KAR 51:017, Sec. 1(3). The SIP version of 401 KAR 51:017 defines "actual emissions" to equal "the average rate, in tons per year, at which the unit actually emitted the pollutant during the two (2) year period which precedes the particular date and is representative of normal source operation." SIP 401 KAR 51:017, Sec. 1(1)(b). Thus, the SIP version of 401 KAR 51:017 does not allow the use of any consecutive 24-months within a 60-month period preceding the date on which the enforceable limit is taken, as assumed by the Division. SOB at 5. The 60-month look back period used by the Division allowed the applicant to select the first 24-months of this period.

The NO_x and SO_2 emissions are higher during these first 24-months than any other consecutive 24-month period because emissions have been steadily declining to comply with NO_x SIP Call and Acid Rain regulations. As demonstrated below, if the definition of "actual emissions" in the SIP version of the NSR rule is used, the creditable emission reductions of NO_x and SO_2 would decline substantially and the project would not net out of NSR.

[2] http://www.answers.com/actual&r=67
[3] http://www.epa.gov/region4/air/sips/ky/51~017.pdf

Division Response:

These are comments about the meaning of the "SIP Gap" and its application to state permitting. The statement that Federal laws "trumps" state law is not correct. The Division's understanding of this relationship would be to say that when state regulations are not as stringent as federal regulation, then the federal agency may enforce the more stringent requirements.

Kentucky has adopted a PSD regulation that is consistent and nearly identical to the current Federal regulation, replacing in a timely manner its previous less stringent regulation. Kentucky expects the U.S. EPA will shortly complete its administrative procedures and update the federal regulations to reflect Kentucky's adoption of the more stringent federal requirements. This permit is issued under the authority of Kentucky law and follows Kentucky regulations.

The Division is aware that there are circumstances where states have adopted less stringent regulations than those in its SIP and that the federal authority has stepped in to enforce the more stringent federal regulatory requirements. That would only apply if Kentucky would attempt to enforce a less stringent requirement; instead of a more stringent requirement.

It is Kentucky's understanding that its regulation would have been finalized into the SIP had it not been for the recent federal court decision concerning clean units and pollution control projects. Neither of these two provisions are invoked in this permit. It is Kentucky's understanding that 401 KAR 51:017 will shortly be incorporated into the SIP with the exception of the PCP and Clean unit exemption.

30)-**B. The NO_x Emission Reduction Is Overestimated**

The creditable NO_x emission reduction was calculated by subtracting the Unit 1 NO_x emission limit of 5,556 ton/yr (Permit, p. 4, Condition 2.e) from 7,041 ton/yr, the average NO_x emissions from Unit 1 in the years 2000 and 2001. SOB at 6, Table 3.2. This results in a reduction of 1,485 ton/yr (7,041 – 5,556 = 1,485). At the outset we were unable to confirm the claimed baseline NO_x emissions of 7,041 ton/yr relied on by the applicant. The EPA Acid Rain website reports 7,134.97 ton/yr in 2000 and 6,818.00 ton/yr in 2001. The average of these two values is 6,976 ton/yr. This discrepancy should be resolved.

Moreover, as discussed above, the wrong baseline was used. Actual emissions for purposes of netting should have been used. Actual emissions are those that occur either immediately prior or in the 2 years prior to the new NO_x limit, which became effective January 1, 2005. Under the state NSR rule, the NO_x emissions immediately prior to the effective data should be used. The NO_x emissions in 2004 were 4,399 ton/yr, substantially lower than the 7,041 ton/yr assumed by the applicant. Under the SIP approved NSR rule, the average NO_x emissions in two prior years, 2003 and 2004, were 4,175 ton/yr, also substantially lower than the 7,041 ton/yr assumed by the applicant. Thus, actual baseline emissions were lower than the proffered permit limit of 5,556 ton/yr and no NO_x reduction is warranted. The NO_x emissions from the project are 1,523 ton/yr. SOB at 6, Table 3.3. Thus, the project triggers PSD for NO_x.

Further, the claimed NO_x reduction was required to comply with another regulatory program, the NO_x SIP Call. Using these reductions to also net of PSD is double dipping. An SCR was installed on Trimble Unit 1 in 2002 to comply with the NO_x SIP Call. The SCR reduces NO_x emissions. Therefore, NO_x emissions declined substantially between 2000, the first year of the two-year baseline period used by the applicant and 2004, the year immediately prior to the effective date of the permit limit. The reductions that occurred between 2002 and 2004 were achieved to comply with the NO_x SIP Call in 40 CFR Part 96. Thus, these reductions cannot also be used to net out of PSD. NSR Manual at A.48.

Division Response:

First, the commenter is in error about double dipping. The "NO_x SIP Call" is a cap and trade program, not the type of emissions reduction being discussed in the draft and never finalized 1990 PSD training manual. The Draft Manual (October 1990) provides that a source "cannot take credit for a decrease that it has had to make, or will have to make, in order to bring an emissions unit into compliance." Unit #1 is in compliance with all applicable standards. There was no regulatory obligation to Trimble Unit #1 to install additional controls; even if credits were required for this unit the source could have purchased these from another source instead of installing new controls. Now that Unit #2 is being constructed, LG&E will have to obtain the necessary emission credits for both the NO_x SIP call and the CAIR rule. Under the commenter's interpretation of PSD, no utility would be able to perform netting if regulated under any cap and trade program. This viewpoint is clearly in error.

31)-**C. The NO_x Emissions Do Not Approximate The Same Qualitative Significance for Public Health and Welfare**

The state and SIP-approved NSR rules both require that a credible decrease in emissions have "approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change." SIP 401 KAR 51:017, Sec. 1(30)(f)(3); State 401 KAR 51:001, Sec. 1(146)(f)(3). To satisfy this requirement, the increases from the project should be offset by decreases at Unit 1 that occur in the same amount and at the same time. In other words, if the project emits 4.17 ton/day of NO_x (Permit, p. 73, Condition 2(g)), the emission reduction at Unit 1 should provide 4.17 ton/day of NO_x reduction each day. Absent such a provision Trimble may not net out of PSD for NO_x.

An SCR was installed on Trimble Unit 1 in 2002 to comply with the NO_x SIP Call, generate NO_x emission reductions, and protect air quality in Kentucky and downwind states. Presumably these reductions were also used as part of the state's maintenance plan and reasonable further progress requirements to achieve compliance with the 1-hour ozone standard. Thus, this SCR has historically only operated during the ozone season. Since this SCR was installed, Trimble's ozone season NO_x emissions have been much lower than during the balance of the year. See, for example, the 2004-2005 data in attachment F. The record we reviewed failed to examine all of the reasons for Trimble reducing NO_x emissions and assessing whether those reasons preclude use of the reductions in a netting calculation

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The applicant proposes to achieve the 1,485 ton/yr NO_x emission reduction at Unit 1 through a combination of increased removal efficiency and increased SCR operating time. SOB at 5. These NO_x emission reductions do not approximate the NO_x emission increases in terms of protecting public health and welfare. Based on historic data summarized in attachment F, the majority of the NO_x reduction is likely to occur by operating the SCR during the non-ozone season because the SCR is currently running at close to design capacity to comply with the NO_x SIP call. In turn, this means a marked increase in NO_x emissions during the ozone season, precisely the time when increased NO_x emissions would have their greatest impact on ozone levels.

Thus, the NO_x emission reduction proposed to offset the NO_x emission increase from the project will not occur in the same amount and at the same time as the emission increases from project. Instead, Trimble will result in an increase in ozone levels downwind of Trimble in the summer months. This will result in an increase in the multitude of human health and welfare effects associated with elevated levels of ozone. Therefore, the proposed NO_x reductions will have less significance for public health and welfare as opposed to the proposed NO_x increases which will cause higher ozone levels. This is unlawful.

Division Response:

Kentucky's understanding is that the federal interpretation is stated in the 1990 DRAFT Manual that states the following about this requirement.

Page A.39

> Current EPA policy is to assume that an emissions decrease will have approximately the same qualitative significance for public health and welfare as that attributed to an increase, unless the reviewing agency has reason to believe that the reduction in ambient concentrations from the emissions decrease will not be sufficient to prevent the proposed emissions increase from causing or contributing to a violation of any NAAQS or PSD increment. In such cases, the applicant must demonstrate that the proposed netting transaction will not cause or contribute to an air quality violation before the emissions reduction may be credited. Also, in situations where a State is implementing an air toxics program, proposed netting transactions may be subject to additional tests regarding the health and welfare equivalency demonstration. For example, a State may prohibit netting between certain groups of toxic subspecies or apply netting ratios greater than the normally required 1:1 between certain groups of toxic pollutants.

Trimble #2 will not affect compliance with the annual NO_x National Ambient Quality Standard. In addition, the Division has no expectations that the short-term SO_2 standards will be exceeded. Additionally, Kentucky's contributions to ozone nonattainment areas are generally considered to be based on regional emissions, not on emission from any single source. Under the NO_x SIP call and CAIR, Kentucky's total emissions are effectively capped.

The commenter has suggested a new regulatory requirement without foundation in the assertion that daily emissions must remain constant.

32)-**D. The SO_2 Emission Reduction Is Overestimated**

The creditable SO_2 emission reduction was calculated by subtracting the Unit 1 SO_2 emission limit of 4,822 ton/yr (Permit, p. 4, Condition 2.f) from 8,047 ton/yr, the average SO_2 emissions from Unit 1 in the years 2001 and 2002. SOB at 6, Table 3.2. This results in a reduction of 3,225 ton/yr (8,047 – 4,822 = 3,225).

However, as discussed above, the wrong baseline was used. Actual emissions for purposes of netting should have been used. Actual emissions are those that occur either immediately prior or in the 2 years prior to the new SO_2 limit, which will allegedly become effective January 1, 2006. Under the state NSR rule, the SO_2 emissions immediately prior to the effective data should be used. The SO_2 emissions in 2004 were 4,725 ton/yr, substantially lower than the 8,047 ton/yr assumed by the applicant. Thus, actual baseline emissions were lower than the proffered permit limit of 4,822 ton/yr, and no SO_2 reduction is warranted. The SO_2 emissions from the project are 3,225 ton/yr. SOB at 6, Table 3.3. Thus, the project triggers PSD for SO_2.

Further, the claimed SO_2 reduction was required to comply with another regulatory program, the Acid Rain Program. The SO_2 emissions from Unit 1 have consistently declined since 1999, from 14,664 ton/yr to 4,725 ton/yr, to comply with the Acid Rain Program, 40 CFR Part 73. *See* annual totals in Attachment A. Using these Acid Rain reductions to also net out of PSD is double dipping. The choice of baseline years that are not immediately prior to the effective date of the SO_2 permit limit, or which are not otherwise adjusted to account for future regulatory requirement, cannot also be used to net out of PSD. NSR Manual at A.48. Finally, the proposed SO2 reduction from Unit 1 that is proposed to be used as a creditable decrease is not federally enforceable at this time. From the statement of basis it appears that Trimble has applied for a permit revision to limit its SO_2 emissions effective January 1, 2006. SOB at 3. Absent an enforceable limit this SO_2 reduction cannot be used for purposes of netting. Any creditable emission decrease should be included in the draft PSD/Title V permit and thereby become federally enforceable.

Division Response:

*The Division has addressed these concerns in its response to "**B. The NO_x Emission Reduction Is Overestimated**"*

33)-**IV. THE PERMIT DOES NOT REQUIRE BACT**
The Permit sets BACT limits for the PC boiler, auxiliary boiler, cooling tower, coal blending facility, material handling operations, ash barge loading fly ash silos, a backup diesel generator, and an emergency diesel fire water pump. We believe that some of these limits should be lower, as set out below. Due to the shortness of time for these comments, we have focused on the PC Boiler, Auxiliary Boilers, and Cooling Tower.

Division Response:

The Division does not concur that the BACT should be lower for reasons enumerated below.

34)-**A. BACT For The PC Boile**r

The permit sets BACT emission limits for PM/PM_{10}, CO, H_2SO_4, and fluoride emissions from the PC boiler.

<u>1. NO_x And SO_2 Emissions From The PC Boiler</u>

The Permit did not set BACT limits for NO_x and SO_2 emissions from the PC boiler because the Division concluded that the project nets out of PSD review. However, as discussed above, the Division's netting analysis appears to be erroneous. The project would result in a net increase in SO_2 and NO_x emissions of greater than 40 ton/yr. Thus, a BACT analysis should be prepared for NO_x and SO_2, the Permit should be revised to include NO_x and SO_2 BACT limits, and a new draft permit should be re-noticed for public review and comment. The Division cannot rely on the BACT analysis performed by the applicant in an earlier version of the Application because that analysis is stale. Lower NO_x and SO_2 emission limits are achievable than the limits proposed in the applicant's prior BACT analysis.

Division Response:

The Division does not concur; please refer to previous comments 27 and 28.

35)-<u>2. PM/PM_{10} Emissions From The PC Boiler</u>

The permit sets a BACT emission limit on “particulate emissions” of 0.018 lb/MMBtu (filterable and condensable). Permit, p. 73, Condition 2.a. There are two problems with this limit.

First, “particulate emissions” is not defined. It is unclear whether the limit is set on particulate matter regardless of particle size (“PM”) or particulate matter with an aerodynamic diameter less than 10 microns (“PM_{10}”) or both. The SOB and application suggest the limit is set on PM and PM_{10}. SOB at 26, Table 5.4; Application, p. 3-1. However, the SOB and Application are not enforceable. BACT limits for particulate matter must be set for both because PSD significance thresholds exist for both. 401 KAR 51:001, Sec. 1(221). Thus, the Permit should be clarified to indicate that the regulated pollutants are PM and PM_{10}.

Division Response:

The term “particulate emissions” is defined in Kentucky’s regulation 401 KAR51:001. This requested change is unnecessary, as Kentucky’s regulation is clear that PM_{10} is a subset of particulate matter. With regard to the permit, PM_{10} is included specifically under operating limitations and again referenced in specific monitoring requirements B.4.e., and again reiterated in Section D. The Division has revisited and revised the permit to ensure consistent usage of terms.

36)-Second, lower PM/PM_{10} limits are achievable and were incorrectly eliminated as BACT by the applicant. Ap., Appx. I. The permits for the following facilities have lower PM/PM_{10} emission limits than those established for Trimble:

- Northampton, PA: 0.0088 lb/MMBtu (1-hr)
- Indeck-Elwood, IL: 0.015 lb/MMBtu (3-hr block)
- Nevco-Sevier, UT: 0.0154 lb/MMBtu (24-hr rolling)

The applicant identified the first listed limit, 0.0088 lb/MMBtu, but rejected it for a number of reasons that we believe are incorrect.

First, the applicant argues that Northampton is much smaller and uses a different combustion technology. Ap., p. I-14. This is irrelevant because the physical and chemical characteristics of flue gas stream and the particulate removal device are similar. The ash content in the Northampton fuel is much higher than the ash content of Trimble’s fuel, which means higher inlet PM concentrations and a more efficient baghouse than required for Trimble. Thus, Northampton is a worst-case.

The fact that a baghouse is used on a CFB, rather than a PC boiler, is not determinative for purposes of a BACT. The underlying combustion method, CFB or a PC boiler, is irrelevant if the gas streams are similar and can be controlled using the same control technologies, as here. NSR Manual, pp. B.10, B.11, B.16 (“The fact that a control option has never been applied to process emission units similar or identical to that proposed does not mean it can be ignored in the BACT analysis if the potential for its application exists.”).

Further, baghouses are routinely used to control PM/PM_{10} from both CFBs and PC boilers. The EPA routinely lumps CFBs and PC boilers when establishing nationwide emission standards for particulate matter. 70 FR 9706 (Feb. 28, 2005). The EPA’s comments on the Longview, WV facility, a large PC boiler, for example, recommended that West Virginia consider the PM BACT limits for two CFBs, Northampton and JEA Northside, in its BACT analysis for a PC boiler.

Second, the applicant asserts that the Northampton PM/PM_{10} limit is filterable only, based on secondhand information from West Virginia that the testing was performed using “modified Method 5.” Ap., p. 1-15. This is incorrect. The stack tests and Pennsylvania’s summary of these tests indicate that the limit is total, not filterable. The Northampton limit has been confirmed in two stack tests -- August 1995 (0.0012 lb/MMBtu)[4] and February 2001 (0.0045 lb/MMBtu).[5] These values are total, comprising the sum of filterable plus condensable measured by EPA/DAPER Method 5. Pennsylvania, and several other states, adopted the original EPA Method 5, which includes the backhalf.

[4] Clean Air Engineering, Report on Emissions Testing Performed for Bechtel Power Company CFB Stack and Dust Collectors, Northampton, Pennsylvania, November 3, 1995.
[5] SGF Consulting Services, Inc., Compliance Test Report for the Measurement of Particulate Emissions, Northampton Generating Company, L.P., Title V Permit #48-00021, February 2001.

Division Response:

The Nevco-Server permit only controls NO_x with a selective non-catalytic reduction with ammonia injection. There is no catalyst to contribute to the formation of sulfuric acid mist; therefore PM condensable emissions are less a factor at this facility. The Nevco-Servier permit does not provide higher removal efficiency than this permit. For these reasons, the Nevco-Servier is not a top down candidate for BACT.

The Division is confused by the reference to the Indeck-Elwood permit. The copy available to the Division states that

> All particulate matter (PM) measured by USEPA Method 5 shall be considered PM_{10} unless PM emissions are tested by USEPA Method 201 or 201A, as specified in 35 IAC 212.108(a). These PM limits do not address condensable particulate matter. (Condensable particulate was addressed in the particulate matter air quality impact analysis required by the PSD rules. For this purpose, the emission rate for condensable particulate matter was estimated to be 0.035 lb/million Btu.)

The Division did discover that the Indeck-Elwood permit is listed by some sources as being total particulates. The Division contacted the Illinois permitting authority, who confirmed that this permit limit was filterable only.

Again, the Indeck-Elwood permit does not contain a SCR, and emits NO_x at a rate more than 200% higher than LG&E.

LG&E has discussed the Northampton facility with Pennsylvania DEP staff and understands that the facility currently is not meeting the permit limits. The Division is aware that Pennsylvania has issued several recent permits for waste coal units that establish higher limits than Northampton and equivalent to or higher than permit limits for Trimble County Unit 2.

37)-<u>3. Visible Emissions</u>

The Permit sets a limit on opacity of 20% based on a 6-minute average. Permit, p. 73, Condition 2.c. This limit is set pursuant to 401 KAR 59.016, Sec. 3(2) and is part of the New Source Performance Standards ("NSPS") for new electric steam generating units. The 20% opacity limit is over 20 years old and is not based on the performance of modern particulate control systems.

The definition of BACT includes a visible emissions standard. 401 KAR 51:001, Sec. 1(25). Opacity is a measure of the degree to which emissions from a source reduce the transmission of light. In other words, opacity is a measure of visible emissions from the source. Opacity can be measured with a continuous opacity monitor and is commonly used as a surrogate to ensure compliance with other pollutants, including particulate matter. The Permit requires the use of a continuous monitoring system for opacity from the PC boiler. Permit, p. 73, Condition 4.a.

The record does not contain a BACT determination for opacity. The opacity level that corresponds to the PM/PM_{10} BACT emission rate should be established for opacity. However, the relationship between opacity and PM/PM_{10} is variable and should be determined for each individual facility. Thus, an interim limit should be established based on the lowest permitted opacity level for a similar facility. Several coal-fired boilers have lower opacity limits including Springerville in Arizona (15%), the Sevier Power Company–Sigurd plant in Utah (10%), Intermountain Power in Utah (10%), and Plum Point Energy in Arkansas (10%). West Virginia limits opacity from coal-fired boilers to 10%.

The Permit should be revised to include a BACT limit for visibility expressed as an opacity limit of 10% based on a 6-minute average. The Permit should also require that an optimization study be conducted within the first 6 months of operation to establish the opacity level that corresponds to the PM/PM_{10} BACT emission level. This opacity level shall be established as BACT for visible emissions from the new PC boiler.

Division Response:

The Division does not concur.

The actual regulatory citation for BACT comes from 401 KAR 51:001 Section 1(25)

(25) "Best available control technology" or "BACT" means an emissions limitation, including a visible emission standard, based on the maximum degree of reduction for each regulated NSR pollutant that will be emitted from a proposed major stationary source or major modification that:…

210) "Regulated NSR pollutant" means the following:

(a) A pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the U.S. EPA;

(b) A pollutant that is subject to any standard promulgated under 41 U.S.C. 7411;

(c) A pollutant that is subject to a standard promulgated under or established by 42 U.S.C. 7671 to 7671q; or

(d) A pollutant that otherwise is subject to regulation under 42 U.S.C. 7401 to 7671q, except that any hazardous air pollutant (HAP) listed in 42 U.S.C. 7412 or added to the list pursuant to 42 U.S.C. 7412(b)(2), which has not been delisted pursuant to 42 U.S.C. 7412(b)(3), is not a regulated NSR pollutant unless the listed HAP is also regulated as a constituent or precursor of a general pollutant listed under 42 U.S.C. 7408.

From 401 KAR 51:001

Section 1 (7) "Air pollutant" means air contaminant.

KRS 224.01-010 Definitions for chapter.
As used in this chapter unless the context clearly indicates otherwise:

(1) "Air contaminant" includes smoke, dust, soot, grime, carbon, or any other particulate matter, radioactive matter, noxious acids, fumes, gases, odor, vapor, or any combination thereof;

An agency may use opacity as an emission limitation. There is neither a federal requirement nor a state requirement to have an opacity limit other than that contained in the applicable regulations. For this to be the case, one would have to read that opacity were a regulated pollutant. Opacity may be an indicator of particulate matter, fumes, gases or vapor, but it is not an independent entity to be regulated. Opacity is the property for the absorption of light, an appropriate indicator for a variety of air pollution concerns, but not a regulated NSR pollutant. The regulated NSR pollutant PM/PM_{10} will be monitored by PM CEMs. This will provide a continuous method for ensuring compliance with the particulate emissions standard.

38)-4. Startups And Shutdowns Excluded From PC Boiler BACT Limit

The Permit excludes periods of startup and shutdown from all emission limits except those limits expressed as tons per year. Permit, p. 73, Condition 2.p. Thus, these periods are excluded from the BACT limits for PM/PM_{10} (3-hr average), CO (30-day rolling average), VOC (30-day rolling average), sulfuric acid mist (30-day rolling average), and fluorides (30-day rolling average).

The SOB clarifies that "the owner or operator shall utilize good work and maintenance practices and manufacturer's recommendations to minimize emissions during, and the frequency and duration of, such startup and shutdown events. The Division concurs that these practices and the supercritical design of boiler constitute BACT for startup and shutdown operations of the new SPC boiler." SOB at 23. Presumably, this refers in part to Section E of the Permit.

BACT emission limits must be met on a continual basis at all levels of operation. Emissions can be higher during startups and shutdowns (less than 50% load) because the pollution control equipment may not operate at peak efficiency or may not operate at all, e.g., the SCR. Startups and shutdowns are part of normal operation and the emissions that occur during these periods should be included in the BACT analysis and limited in the permit.[6] In re Tallmadge Energy Center, Order Denying Review in Part and Remanding in Part, PSD Appeal No. 02-12 (EAB May 21, 2003) sip op. at 24 ("BACT requirements cannot be waived or otherwise ignored during periods of startup and shutdown"); In re RockGen Energy Center, 8 E.A.D. 536, 553-55 (EAB 1999) (holding that PSD permits may not contain blanket exemptions allowing emissions in excess of BACT limits during startup and shutdown); In re Indeck-Niles Energy Center, Order Denying Review, PSD Appeal No. 04-01 (EAB September 30, 2004) at 16, note 9.

The Division relies on the general duty rule in Permit Section E for startup and shutdown periods. This rule did not arise out of a top-down BACT analysis and is no substitute for specific BACT limits. The general duty rule does not explain exactly how emissions would be minimized during startups and shutdown, but rather would use monitoring results, review of operating and maintenance procedures, manufacturer's recommendations on minimizing emissions, and inspection. The operating and maintenance procedures and manufacturer's recommendations are not in the permit file we reviewed and thus have not been subject to public review.

Presumably, these plans would be developed in the future. However, the Permit does not require that they be submitted to the agency for approval or be subject to public notice, review, and appeal, as they must be if they are to satisfy BACT. Tallmadge, slip op. at 26. Further, the Permit does not specify what conditions might be included in the plans or indicate what criteria would be used in approving the plans, or even that they would be approved. RockGen, 8 E.A.D. at 553.

The permit file we reviewed contains no evidence that the Division considered ways to eliminate or reduce excess emissions during startup and shutdown, beyond the specification of plans that would be developed in the future. Instead the crucial emissions elimination/reduction analysis has been assigned to the permittee, to be conducted in the future, without any approval whatsoever. This scheme is not acceptable under the CAA. Tallmadge, slip op at 26-27; RockGen, 8 E.A.D. 536, 551-555. The DAQ must describe the design, control, and methodological, or other changes that are appropriate for inclusion in the Permit to minimize allowed excess emissions during startup and shutdown. Tallmadge, slip op. at 27.

We recommend that the BACT analysis be revised to set limits that include periods of startup or shutdown, or expanded to set separate limits that apply during periods of startup and shutdown. Tallmadge, slip op. at 28. This analysis should seek to minimize these emissions by evaluating options such as heating the flue gas during startup.

6 See, e.g., Memorandum from John B. Rasnic to Linda M. Murpy January 28, 1993; Memorandum from Kathleen M. Bennett to Regional Administrators, Re: Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions, February 15, 1983; Memorandum from Kathleen M. Bennett to Regional Administrators, Re: Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions, September 28, 1983

Division Response:

This is a base load-generating unit designed to operate at a high capacity factor, inherently startup and shutdown events will be kept to an absolute minimum for this unit. However, LG&E acknowledges and concurs with U.S. EPA's request to develop a startup/shut down plan, which will be reviewed by the Division, and available for public review. This plan will be used to assure that the requirements of the permit and 401 KAR 50:055 are complied with during periods of startup and shutdown. Pursuant to 401 KAR 50:055, emissions must be minimized in a manner consistent with good air pollution control practices at all times. See U.S EPA Region 4 comment number 10.

39)-<u>5. Separate Limits Required For Various Coal Types</u>
The project will burn two types of coal – eastern bituminous and a blend of eastern bituminous and western subbituminous coal. Ap., p. 2-3; Permit, p. 73, Unit 31 Description. The BACT emission limits, however, appear to be based on the worst-case fuel, the eastern bituminous coal. The BACT emission limits may be different, and most notably, much lower for some pollutants, e.g., SO_2, H_2SO_4, for the blend than the eastern bituminous coal. The BACT limits should be set at a level that reflects the lowest emission rate achievable and that may dictate the fuel blend that should be required for this facility.

Division Response:

Commenter has suggested that the permit needs different emission limits set for the different types of fuels being combusted. Given the variability of ash, sulfur, moisture, mercury, and chlorine even within the broad category of Eastern Bituminous coal; the Division does not see a feasible manner nor need to set variable limits. BACT has been appropriately set to minimize emissions.

40)-**B. Auxiliary Boiler**
<u>1. Clean Fuel</u>

The auxiliary boiler will burn No. 2 fuel oil. The facility includes six gas turbines. Thus, clearly, there is a source of natural gas at the site. Natural gas is BACT for the auxiliary boilers when it is available, as here.

Division Response:

The applicant is not subject to a BACT review for NO_x and SO_2 for the auxiliary boiler. There is a negligible difference inPM, VOC, and CO emissions from a 40 mmBtu/hr boiler firing natural gas versus one firing oil. From AP-42, emission for CO will be less and PM (total) emissions slightly higher. These emission factors do not take into account that the permit requires very low sulfur fuel, which will have lower emission than standard fuel oil. The permit limits the operation of this small industrial boiler to less than 1000 hours of operation per year.

41)-**C. BACT For The Cooling Tower**

The Permit sets a BACT limit for PM/PM_{10} emissions from the cooling tower as 0.001% drift eliminators. Permit, p. 73, Unit 41, Condition 2. The drift rate is the percent of the circulating water that is allowed to escape into the air. The smaller the number the better the control and the lower the PM emissions. This limit is inconsistent with the definition of BACT, is not BACT for the new cooling tower, and is not enforceable. Each of these issues is discussed below.

1. The Proposed Limit Is Inconsistent With The Definition Of BACT

The Permit does not set a PM/PM_{10} emission limit for the new cooling tower. BACT means "an emissions limitation ." 401 KAR 51:001, Sec. 1(25). The Division may only impose a "design, equipment, work practice, or operational standard or combination of standards approved by the cabinet if: 1. The cabinet determines technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emission standard infeasible." 401 KAR 51:001, Sec. 1(25)(c). The Division has not demonstrated any constraints to the setting of a specific PM/PM_{10} emission limit for the cooling tower. The Application calculates PM_{10} emissions from the new cooling tower as 0.34 lb/hr.

We are not aware of any constraint to the imposition of a PM/PM_{10} emission limit for the cooling tower. Thus, the Permit should be revised to establish a PM/PM_{10} emission limit for the new cooling tower.

2. The Proposed Drift Efficiency Is Not BACT

New Unit 2 will use the existing natural draft cooling tower, which is currently being used to cool Unit 1. A new cooling tower will be built to replace the cooling demand of Unit 1 currently supplied by the existing natural draft tower. The subject Permit proposes a 0.001% drift eliminator as BACT for the new cooling tower for Unit 1. This is not BACT for the new cooling tower.

The BACT analysis acknowledges many similar cooling towers that have been permitted at 0.0005% drift. Ap., p. I-30. However, the BACT analysis is fundamentally flawed. Ap., Appx. I, Sec. 8.2.

First, it only evaluated a 0.001% eliminator for the new tower. It did not evaluate a high efficiency drift eliminator (0.0005%). The selected option, existing tower for Unit 2 and new tower for Unit 1, equipped with a 0.0005% eliminator would remove more PM/PM_{10} and thus should have been evaluated as the top option.

Second, the cost analysis is defective. It allocates 100% of the cost of the cooling system to the control of PM, rather than the cost of the control method itself, i.e., the drift eliminator. This would be like including the cost of the boiler in a cost effective analysis for an SCR. A high efficiency drift eliminator by itself is highly cost effective. However, if one includes the cost of the cooling tower, which is required to cool the condensate, not control PM emission, the costs are not cost effective.

Third, the cost analysis is not supported. The design basis, battery limits, and costs of individual components should be identified and supported. Finally, high efficiency drift eliminators are widely used on coal fired power plants. The Application identifies four. Ap., p. I-30. We are aware of many others, including Intermountain, UT; Newmont, NV; Rocky Mountain Power, MT; Comanche Generating Station, CO; and the proposed Indeck-Elwood, IL. When a control alternative has been widely used, as here, it can only be eliminated as BACT if a demonstration is made that unusual circumstances exist that distinguish the source from all others. No such demonstration has been made and we believe none is likely. Thus, putting aside dry cooling for the purposes of this comment, we conclude that BACT for the new cooling tower is a high efficiency drift eliminator designed to achieve a 0.0005% drift rate.

<u>3. The Cooling Towers Limits Are Not Enforceable</u>

The Permit identifies two applicable requirements for the cooling towers, 401KAR 63:010, Sec. 3 (fugitive emissions) and 401 KAR 51:017 (BACT). These are implemented by imposing operating and emission limits:

1. <u>Operating Limitations:</u>
a) Pursuant to Regulation 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.
b) Pursuant to Regulation 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

2. <u>Emission Limitations:</u>
a) Pursuant to regulation 401 KAR 51:017, the cooling towers shall utilize 0.001% drift eliminators.
b) Pursuant to Regulation 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

The Permit states that no testing is required to determine compliance with these limits, but the SOB indicates monthly measurement of total dissolved solids ("TDS") and circulating water. SOB at 31. The Permit requires recordkeeping for these two parameters, but not their measurement. Permit, p. 73, Unit 41, Condition 5. This collection of conditions is contradictory and ambiguous and thus not enforceable.

The drift rate of 0.001% in the Permit is not enforceable as a practical matter. The Permit does not specify any monitoring to determine if the proposed drift rate is being met. Drift rate is measured using a special drift test conducted by a certified test firm. These tests are commonly performed on cooling towers and are commercially available. The Permit also does not specify a time period to demonstrate compliance with the drift rate, i.e., averaging time or the frequency for monitoring and reporting the drift rate.

Particulate emissions coming out of the tower depend on the drift rate, circulating water flow rate, and total dissolved solids ("TDS") in the circulating water. Particulate emissions must be measured in the tower exhaust or calculated from the circulating water rate, TDS in the circulating water, and drift rate. The Permit requires only that records be kept of water circulation and TDS, which by themselves are not adequate to determine either drift rate or PM/PM_{10} emissions. The Permit does not require that water circulation be measured nor specify any testing frequency, testing methods, or testing locations.

In sum, the Permit sets a BACT control efficiency, with no supporting monitoring, while the SOB contains monitoring to determine compliance with a BACT emission rate, which is not in either the SOB or the Permit. This mix of conditions is not enforceable because they contain no averaging time; they do not require any monitoring of drift rate, circulating water rate, or circulating water TDS; they do not specify testing frequency, methods, or location; and they do not require that PM/PM_{10} emission be calculated and compared to an emission limit. Thus, there is no way to assure compliance with cooling tower BACT.

Division Response:

1. *The Division acknowledges the comment, but does not agree that the numerical limit should be set as a cooling tower BACT for fugitives. BACT has been set as design parameters for the drift eliminators.*

2. *Particulate matter from cooling towers is generated by the presence of dissolved and suspended solids in the cooling tower circulation water, which is potentially lost as "drift" or moisture droplets that are suspended in the air moving out of the cooling tower. A portion of the water droplets emitted from the tower exhausts will evaporate leaving the suspended or dissolved solids in the atmosphere and thus subject to dispersion. The particulate emissions from the new linear mechanical draft cooling tower (LMDCT) can be controlled by minimizing the amount of water drift that occurs. This can be accomplished by using high efficiency drift eliminators. For the LMDCT, the cycles of concentration and drift eliminators will provide design drift rate of 0.0005 percen. This represents the most stringent level of drift elimination that has been permitted. Thus, a cooling tower design drift rate of 0.0005 percent represents the most stringent level of drift elimination is proposed as BACT for the LMDCT*

3. *Requirements to monitor and record monthly TDS content have been added to the permit. The Division has added to the permit's initial testing to determine drift rate for the cooling tower.*

42)-**V. PORTIONS OF THE PERMIT ARE NOT ENFORCEABLE**
A. Compliance Provisions Are In the SOB But Not The Permit

Most of the procedures that would be used to determine compliance with Permit conditions are summarized in the SOB, but are not included in the Permit. These include the initial and periodic stack testing for PM/PM_{10}, VOCs, fluoride, sulfuric acid mist, mercury, and lead emissions from the PC boiler. SOB, pp. 26-28, Table 5.4. The Permit itself contains the sulfuric acid mist and fluoride monitoring, but includes it in Section B.4.j in Table 1, CAM Monitoring Approach. The Preamble to the CAM regulations makes it clear that compliance with CAM indicator provisions does not make an applicable requirement enforceable. 62 FR 54,900-54,947.[7]

The SOB is not an enforceable document. The purpose of the Title V program is to include all of the provisions, including compliance provisions, in a single document, the Title V Permit. Thus, we recommend that the specific compliance provisions now found only in the SOB be moved into the Permit and that the Permit clearly state that these provisions are intended to enforce subject Permit limits.

[7] *We are citing to the version that is available on EPA's CAM website at www.epa.gov/ttn/emc/cam.html.*

Division Response:

Annual performance testing for PM/PM_{10} VOCs and lead have been added to the permit. CEMs *and other methods shall provide continuing compliance for PM/PM_{10}, fluorides, sulfuric acid mist and mercury. The initial testing requirements are contained in Section D of the permit.*

This permit will use the monitoring approach contained in CAM to ensure compliance for sulfuric acid mist and fluoride emission limits.

43)-**B. CAM Compliance Provisions Are Not Adequate To Ensure Compliance With Permit Limits**

The Permit includes CAM monitoring for two pollutants, sulfuric acid mist and fluorides. The following subsection comments on the substance of the proposed indicator monitoring approach. The Permit appears to rely on this CAM monitoring to assure compliance with the BACT limits on sulfuric acid mist and fluorides. SOB, pp. 27-28, Table 5.4. This section comments on the use of CAM monitoring to assure compliance with permit limits.

The CAM monitoring requirements do not assure compliance with the sulfuric acid mist and fluoride BACT limits. Compliance with CAM indicator provisions, such as proposed in the Trimble Permit, does not make an applicable requirement, e.g., a BACT limit, enforceable. 62 FR 54,900-54,947.[8]

The EPA has objected to Title V permits in Region 4 for failure to include explicit statements that the indicators are not set as enforceable limits. For example, in the Tampa Electric Company's F.J. Gannon Station case, the EPA objected to the Title V permit, stating:

> While the permit does include parametric monitoring of emission unit and control equipment operation in the O&M plans for these units… the parametric monitoring scheme that been specified is not adequate. The parameters to be monitored and the frequency of monitoring have been specified in the permit, *but the parameters have not been set as enforceable limits. In order to make the parametric monitoring conditions enforceable, a correlation needs to be developed between the control equipment parameter(s) to be monitored and the pollutant emission levels.* The source needs to provide an adequate demonstration (historical data, performance test, etc.) to support the approach used. In addition, an acceptable performance range for each parameter that is to be monitored should be established. The range, or the procedure used to establish the parametric ranges that are representative of proper operation of the control equipment, and the frequency for re-evaluating the range should be specified in the permit. Also, the permit should include a condition requiring a performance test to be conducted if an emission unit operates outside of the acceptable range for a specified percentage of normal operating time. The Department should set the appropriate percentage of the operating time would serve as trigger for this testing require.

U.S. EPA Region 4 Objection, Proposed Part 70 Operating Permit, Tampa Electric Company, F.J. Gannon Station, Permit No. 0570040-002-AV. This theme will be repeated below for each parameter that is monitored through an indicator because none of the proposed indicators are set as enforceable limits.

Thus, unless the Permit explicitly states that an exceedance of an indicator is a violation of the underlying applicable requirement, the indicator does not assure that the underlying requirement is enforceable, it only provides a reasonable assurance of compliance. The indicator approach proposed by DAQ to assure compliance with Permit limits is probative. Compliance must be determined by a performance test or other similar data in which actual stack emissions are measured.

Finally, the CAM section of the Permit only addresses sulfuric acid mist and fluoride. We believe that CAM monitoring also should be required for other pollutants, including total PM/PM_{10} (the CEMS only measures filterable) and lead emissions from the PC boiler.

[8] *We are citing to the version that is available on EPA's CAM website at www.epa.gov/ttn/emc/cam.html.*

Division Response:

The Division does not concur. CAM is not required for lead since this unit is not a pollutant-specific emissions unit (PSEU) as defined by 40 CFR 64.

Condition D.6 of the permit states, 'Continuing compliance with the emission standards for H_2SO_4 mist and Fluorides shall be determined by following provision of the CAM plan in Section B of this permit.'

See response to U.S EPA comment #7.

44)-**C. The PC Boiler Limit on Toxic Substances Are Not Enforceable**

The Permit states that compliance with the limits on PM/PM_{10}, SO_2, CO, and Hg shall constitute compliance with 401 KAR 63:020 with respect to toxic substances. Permit, p. 73, Condition 2.o. This condition assumes that all of the toxic substances emitted by the project are related to these four pollutants and that the emission limits on these four pollutants are low enough to assure that emissions of toxic substances are not harmful to health and welfare of humans, animals and plants. 410 KAR 63:020, Sec. 3. There are two problems with these assumptions.

First, the file we reviewed contained no evidence that the Division has identified the specific toxic substances that would be emitted by Trimble, quantified their emissions, and performed a risk assessment to determine if the emissions of these substances are harmful to health and welfare of humans, animals and plants.

Second, the file we reviewed contained no evidence that there is any relationship between these four regulated pollutants and the unidentified toxic substances they are designed to control. Based on regression analysis of coal quality data in the Thoroughbred and cases, most of the toxic substances of concern are not related to these four pollutants. Dioxins, mercury, and selenium, for example, are not related to SO_2, PM/PM_{10}, NO_x, or CO emissions. Further, there is no evidence that the specific limits imposed on PM/PM_{10}, SO_2, CO, and Hg are low enough to assure that emissions of all toxic substances are not harmful to health and welfare of humans, animals, and plants.

Thus, we recommend that the Division prepare a human health and ecological risk assessment to determine the impact of project emissions on the health and welfare of humans, animals, and plants. This could be done as part of the U.S. EPA's obligation to consider impacts on endangered species. See below. The pollutants and emission limits used in this assessment should be established as Permit limits.

Division Response:

The Division does not concur. U.S. EPA conducted extensive studies of risk posed by hazardous air pollutants (HAPs) from electric utility generating units and determined that mercury is the only HAP from coal-fired power plants that posed a risk sufficient to warrant regulation 65 Fed. Reg. 79,285-79,831 (December 20, 2000). U.S. EPA revised its previous regulatory determination and removed coal fired electric utility steam generating units from the CAA section 112 (c), source category listing- 70 Fed. Reg. 15,994-16,035 (March 29, 2005) thus indicating power plants should no longer be covered under the maximum achievable control (MACT) technology program to control HAPs. The pollutants that commenters expressed concern about are particulate in nature and will be controlled through the existing pollution control train.

In addition, the Clean Air Mercury Rule (CAMR) which was published in 70 Fed. Reg. 28,605-28,700 (May 18, 2005), results in the removal of mercury from consideration under 401 KAR 63:020, since the NSPS is now established for that pollutant.

45)-**D. The PC Boiler Lead Limit Is Not Enforceable**

The Permit sets a limit on lead of 0.55 ton/yr based on a 12-month rolling total. Permit, p. 73, Condition 2.m. This limit is not enforceable.

First, the averaging time is ambiguous and excessively long. It is unclear whether the limit is an annual average rolled monthly or an annual average rolled annually. Regardless, these averaging times are too long because an inspector cannot determine if they are being complied with.

Second, the limit is slightly less than the PSD significance threshold of 0.6 ton/yr. 401 KAR 51:017, Sec. 1(221)(a). If emissions exceed 0.6 ton/yr, BACT for lead would be required. Thus, the new unit is a synthetic minor for lead. Synthetic minor limits generally require both an emission limit and a production limit to assure that emissions remain below the significance threshold. Thus, we recommend that the Permit be modified to limit the amount of coal than can burned and the lead content of the coal.

Third, the Permit states the limit as 0.55 ton/y, the SOB states the limit is 0.055 ton/yr, and the Application reports lead emissions as 0.15 ton/yr (0.035 lb/hr). It is unclear which is correct.

Finally, the Permit itself does not require any testing to determine if the lead limit is met. The only compliance testing is found in the SOB, which indicates initial and annual performance tests and the use of PM as a surrogate, monitored by the PM CEMS. SOB at 28, Table 5.4. Lead is very variable in coal and can vary over an order of magnitude or more, depending upon the sources of the coal. The variability would be much greater than for a mine-mouth plant because multiple sources could supply the facility. Further, lead is not related to the ash content of coals and thus PM emissions would likely not be related to lead emissions.

Thus, we recommend that the proposed testing in the SOB be included in the Permit and be supplemented with daily coal sampling, composited and analyzed monthly for lead as the primary compliance method. If indicator monitoring is retained, we recommend that a study be conducted to establish a relationship between lead and PM. The relationship should be used to establish the level(s) of PM that assure compliance with the lead limit and used to predict lead emissions. The relationship also should be confirmed at least annually to assure that it continues to apply. The Permit should be modified to state that an exceedance of this level is a per se violation of the underlying lead limit. Otherwise, the stipulated indicator monitoring does not assure compliance with the lead limit.

Division Response:

The Division does not concur. This permit is not a synthetic minor permit for lead. The Division reviewed the information and determined that potential emissions from this construction do not equal or exceed 0.6 tons per year, which is the PSD significant threshold. The Division added a 0.55 tons per year emission limit condition that was the practical cap indicating that BACT was not required for lead. This was for purposes of clarity and thoroughness. The nonapplicabillity of BACT to lead is confirmed with an annual performance test.

46)-**D. The PC Boiler Sulfuric Acid Mist Limit Is Not Enforceable**

The Permit sets a limit of 26.6 lb/hr based on a 30-day rolling average on sulfuric acid mist ("SAM"). Permit, p. 73, Condition 2.j. This limit is not enforceable.

First, we note that the applicant's BACT analysis concluded that BACT is 26.6 lb/hr based on a 3 hour rolling average, to coincide with three 1-hour performance tests. Ap., p. I-29.

We recommend that the averaging time be reduced to a 3-hour period because a 30-day rolling average cannot be determined from a 3-hour long stack test. Second, the Permit only requires CAM monitoring for SAM. This monitoring includes SO_2 CEMS plus an initial source test, weekly coal sampling with quarterly composites, and establishing a correlation between SO_2 and SAM and an indicator range. Permit, p. 73, Table 1. As discussed above, we are concerned that CAM monitoring cannot be used to assure compliance with BACT emission limits. The only compliance testing is in the SOB, which indicates an initial performance test and the use of SO_2 as a surrogate, monitored by the SO_2 CEMS. SOB at 28, Table 5.4. We support the indicator approach if appropriately implemented. However, we have some concerns about the proposed monitoring.

First, we are concerned that SO_2 is not a good indicator of SAM. Sulfuric acid is related to SO_2, but in a very complex, nonlinear manner. The amount of SAM that is formed depends on the duct SO_2 concentration at the inlet to the scrubber, the air heater and economizer gas outlet temperatures, the coal SO_2 in lb/MMBtu, the SO_2 to SO_3 conversion rate of the boiler, the SO_2 to SO_3 conversion rate of the SCR, and the amount of SO_3 removed by the air heater, fabric filter baghouse, SO_2 scrubber, and WESP. All of these factors vary over time and in an unpredictable manner. Thus, measuring coal sulfur content or SO_2 at the stack conveys little information about accompanying SAM emissions.

Thus, we recommend that the Permit be modified to require a study to establish a relationship between SO_2 and SAM. This relationship will likely require other variables, such as temperature and coal sulfur content, to reasonably predict SAM from SO_2. The relationship should be used to establish the level(s) of SO_2 that assure compliance with the SAM limit and used to permit SAM levels on a routine basis. The relationship should be confirmed at least annually to assure that it continues to apply. The Permit should be revised to that any other variables required to predict SAM be monitored, recorded, and reported. Further, we recommend that the Permit be modified to state that an exceedance of a SO_2 level(s) is a per se violation of the underlying SAM limit. Otherwise, the stipulated indicator monitoring does not assure compliance with the SAM limit.

Second, coal sampling is proposed. The Permit does not identify the parameter(s) that would be monitored in the coal, the location where the sample(s) would be collected (mine, pulverizer), the sampling methods that would be used, the test methods that would be used, or how the resulting data would be used to determine compliance with a SAM limit. These should all be specified in the Permit and subject to public review. We also believe that weekly samples composited quarterly is not adequate to assure continuous compliance with a BACT limit. A minimum of daily samples should be collected and analyzed for at least sulfur, heat content, and ash content. This level of sampling is routinely conducted at coal plants and should be reported to the Division to demonstrate compliance with Permit limits.

Division Response:

This permit has been modified to include a three hour rolling average; see response to U.S. EPA Comment #4. The Division concurs that monitoring of the WESP for control of SAM is the appropriate monitoring techniques, and has revised the permit. Proper operation of the WESP will ensure compliance with the emission limitation. See response to U.S. EPA Comment #8.

47)-**E. The PC Boiler Mercury Limit Is Not Enforceable**

The Permit sets a limit of 13 x 10^{-6} lbs/MWh on mercury, based on a 12-month rolling average. This limit is not enforceable. First, the Permit does not indicate whether the megawatt hours is gross or net. The SOB indicates gross, but the SOB is not enforceable. SOB at 28, Table 5.4. The difference can range 10-15 percent. Second, the averaging time is ambiguous and excessively long. It is unclear whether the limit is an annual average rolled monthly or an annual average rolled annually. Regardless, these averaging times are too long because an inspector cannot determine if they are being complied with. Compliance will be determined with a CEMS, which means hourly data will be available. Thus, the Permit should be revised to clarify whether gross or net was intended and to specify a shorter averaging time, no longer than 24-hours.

Division Response:

The Division concursin part and the permit has been clarified to state that the limit is on a gross output basis.

The Division does not concur that the compliance period is not enforceable. The compliance period for the mercury limit is identical to the federal New Source Performance Standards ("NSPS") for electric utility steam generating units promulgated as part of the federal Clean Air Mercury Rule ("CAMR"). 70 Fed. Reg. 28605 (May 18, 2005). The averaging period for the new NSPS mercury limit is a 12-month rolling average. 40 CFR § 60.45a(a). U.S. EPA has specifically endorsed the appropriateness of a 12-month rolling average for mercury emissions. "Compliance with the final standards of performance for Hg(Mercury) will be on a 12-month rolling average basis, as explained below. This compliance period is appropriate given the nature of the health hazard presented by Hg." 70 Fed. Reg. at 28610. There is no regulatory basis for a short-term mercury limit of 24 hours. The limit is enforceable through the use of a CEM as required by CAMR.

48)-**F. The PC Boiler VOC Limit Is Not Enforceable**

The Permit sets a limit of 0.0032 lb/MMBtu on VOC emissions, based on a 30-day rolling average. Compliance with this limit "shall be demonstrated by compliance with Subsection 2(f) above," which is the CO emission limit. Permit, p. 73, Condition 2.i. The SOB clarifies that CO emissions is used as a surrogate for VOC emissions. SOB, p. 27, Table 5.4. This limit is not enforceable because CO and VOC are separate pollutants that are not directly related and are affected by different factors.

We support the indicator approach if appropriately implemented. The Permit should require a study be conducted to establish a relationship between CO and VOC. This relationship should be used to establish the level(s) of CO that assure compliance with the VOC limit and used to predict

VOC levels. The relationship should be confirmed at least annually to assure that it continues to apply. The Permit be modified to state that a violation of a specific level(s) of the CO surrogate constitutes a per se violation of the underlying VOC limit.

Division Response:

The Division does not concur. This is a standard approach used in permits nationwide. The Division has revised the VOC compliance period to reflect the compliance testing. The permit has been revised to require annual performance testing of VOC, as was indicated in the statement of basis. The permittee has agreed to evaluate the relationship between CO and VOC during the initial and annual stack tests.

49)-**G. The PC Boiler PM/PM_{10} Limit Is Not Enforceable**

The Permit sets a limit on particulate emissions comprising the sum of filterable and condensable particulates. Permit, p. 73, Condition 2.a. A PM CEMS will be used to determine compliance with this limit. *Id.*, Condition 4.e. The Permit itself does not contain any additional monitoring to determine compliance with this limit. However, the SOB indicates that initial and annual performance tests also would be conducted to determine compliance. SOB at 26, Table 5.4. This additional testing should be moved into the Permit to assure that the PM/PM_{10} limits are enforceable.

The list of test methods in the "compliance/testing" column is ambiguous and should be clarified. We recommend that this testing be modified to address the following: (1) eliminate Method 9 (which is used to determine opacity, not PM/PM_{10}); (2) clarify that Method 5 shall be used to determine total filterable PM; (3) to clarify that Methods 201 or 201A shall be used to determine filterable PM_{10}; and (4) to clarify that Method 202 shall be used to determine condensable PM/PM_{10} until EPA approves an alternate.

The SOB suggests that an alternate Method 202 can be approved in the permit or any other approved alternative method can be used. This language is ambiguous and appears to grant authority to use any alternative method approved by any party. Test methods used to determine compliance with federally enforceable permit conditions must be approved by the U.S. EPA. There are currently no U.S. EPA approved alternative methods for measuring condensable PM/PM_{10}.

Division Response:

The Division does not concur. Kentucky has a SIP approved program, and Kentucky regulations and authority govern the use of alternative test methods under PSD. The Division believes this is the appropriate language to approve an alternative method. Kentucky clearly can specify or approve the use of an alternative method that provides results that are analytically sufficient to indicate whether a source is in compliance with the BACT limit. Kentucky would need approval only for an alternative method for standards contained in 40 C.F.R. 60, 40 C.F.R. 61, or 40 C.F.R. 63.

The Division concurs that there were testing requirements addressed in the Statement of Basis that were not addressed in the permit. The Division has corrected the omission of those testing requirements.

The Division does not concur that table 5.4 in the SOB is ambiguous. The test methods clearly define the pollutant for which the test is being conducted.

50)-**H. Good Combustion Control Is Not Defined**

The Permit indicates that BACT for CO is "good combustion control." Permit, p.73, Condition 1. The Permit also indicates that "good combustion control" is one of the methods that will be used to control toxic substances. Permit, p. 73, Condition 2.n. The term "good combustion control" is not defined and thus is not enforceable. Combustion controls include a wide range of techniques, including staged combustion, excess air, low-NOx or ultra low-NOx, and combustion optimization systems. The file that we reviewed does not identify the specific combustion controls that would be used to assure the VOC BACT limit is continuously met. The Permit should be revised to define the term "good combustion control" so that it is practically enforceable.

Division Response:

The phrase "good combustion control" is pervasive in permitting, regulatory and industrial arenas. In addition, a review of U.S. EPA's RACT/BACT/LAER Clearinghouse indicates that good combustion control is the listed method for CO emission from coal-fired boilers. The Division does not concur that a term in common usage needs to be redefined in each permit. The permittee will be using a CEM to ensure compliance with the permit's CO limit. The permit has set a BACT limit for CO.

51)-**VI. U.S. EPA HAS NOT COMPLIED WITH THE ENDANGERED SPECIES ACT**

According to the U.S. Fish and Wildlife Service Kentucky has forty-two species that are listed on the federal endangered species list.[9] This list includes 33 animals and 9 plants. Based on the information we have reviewed there does not appear to have been any consultation between U.S. EPA and the U.S. Fish and Wildlife Service at this stage in the proceedings to ensure that the proposed Trimble project will not adversely impact these listed species. Section 7 of the Endangered Species Act requires every federal agency "to insure that any action authorized, funded or carried out by such agency is not likely to jeopardize the continued existence" of any endangered or threatened species or adversely modify critical habitat. 16 U.S.C. § 1536(a)(2). To accomplish this substantive requirement, Section 7 imposes a procedural duty on each federal agency to consult with the FWS (or the National Marine Fisheries Services in cases involving marine species) before engaging in any discretionary action which "may affect" a protected species. 50 C.F.R. § 402.14(a); *see* 16 U.S.C. § 1536(a)(2); *Natural Res. Defense Council v.*

[9] *http://ecos.fws.gov/tess_public/servlet/gov.doi.tess_public.servlets.UsaLists?usMap=1&status=listed&state=KY.*

Houston, 146 F.3d 1118, 1125 (9th Cir. 1998); *Sierra Club v. Babbitt*, 65 F.3d 1502, 1504-05 (9th Cir. 1995).

Federal agencies are required to review their actions "at the earliest possible time to determine whether any action may affect listed species or critical habitat." 50 C.F.R. § 402.14(a). In addition, the FWS may independently request a federal agency to enter into consultation "if [the FWS] identifies any action of that agency that may affect listed species or critical habitat and for which there has been no consultation." *Id.* "The purpose of the consultation procedure is to allow the Service to determine whether the federal action is likely to jeopardize the survival of a protected species or result in the destruction or adverse modification of its critical habitat and, if so, to identify reasonable and prudent alternatives which will avoid the action's unfavorable impacts." *Sierra Club v. Babbitt*, 65 F.3d at 1505; *see* 16 U.S.C. § 1536(b)(3)(A). There are only two recognized exceptions to the requirement of formal consultations in cases where an agency action "may affect" listed species. These are: (1) when, as a result of the preparation of a biological assessment under 50 C.F.R. § 402.12, or as a result of informal consultation with the Service under § 402.13, "the federal agency determines, with the written concurrence of the Director, that the proposed action is not likely to adversely affect any listed species or critical habitat;" and (2) when a preliminary biological opinion, issued after early consultation under § 402.11, is confirmed as the final biological opinion. 50 C.F.R. § 402.14(b) (emphasis added).

Accordingly, if an agency proposes to authorize an activity in an area that "contains threatened or endangered species" it may forego Section 7 consultation only if it determines that its action will not "affect" listed species, and the FWS expressly concurs with that determination. Section 7 further prohibits the "irreversible or irretrievable commitment of resources" during and "before * * * initiat[ing] formal consultation." *Houston*, 146 F.3d at 1125; 1128 n.6.

U.S. EPA has a mandatory duty to review the proposed Trimble project for compliance with the ESA. Because U.S. EPA cannot delegate its ESA consultation obligations it must necessarily have reserved that authority when it approved the Kentucky PSD program. A state that is administering a SIP approved PSD permit program may not issue a final PSD permit until such time as U.S. EPA has completed its consultation obligations and the results of any consultation have been incorporated into the permitting process. The situation is the same for SIP-approved and SIP-delegated PSD programs. The delegation agreement between Region 10 and the State of Washington requires that "[i]n order to assist EPA in carrying out its responsibilities under Section of the Endangered Species Act (ESA) … for federal PSD permits, [the state] shall: … [r]efrain from issuing a final PSD permit until EPA has notified [the state]
that EPA has satisfied its obligation, if any, under the ESA …." Agreement for Partial Delegation of the Federal Prevention of Significant Deterioration (PSD) Program of the United States Environmental Protection Agency, Region 10 to the State of Washington Department of Ecology (March 3, 2003). Kentucky cannot issue the Trimble PSD permit until such time as U.S. EPA has fulfilled its consultation obligations.

There are multiple examples of how the proposed Trimble plant could impact endangered plants and animals. As demonstrated by the recent ESA consultation conducted for the proposed Indeck-Elwood coal plant, air emissions from coal plants can impact endangered plants and animals in several ways, including acid-contaminated rain and nitrogen deposition changing the vegetation composition and driving out endangered plant species. Plants are particularly at risk because the pH of the rain close to the proposed Indeck (sic) power plant is estimated to be as low as 2.6, akin to vinegar. These estimates do not consider raindrops falling on vegetation and as the acidic raindrops evaporate the acidity increases even more. Attached in support of this comment are four documents, the study conducted by Indeck's (sic)consultants, an addendum to that study, U.S. EPA's summary of the impacts and FWS's review of that information. This example is not intended to be exhaustive. The first step in the analysis has to be to identify what endangered plants and animals reside within the zone of potential impacts from this coal-fired power plant.

Division Response:

The endangered species act is not under the purview of the Kentucky Division for Air Quality. This is not a question for the Kentucky Division for Air Quality. Kentucky is aware of the ongoing challenges that are being brought to U.S. EPA on this matter, and we are aware that on September 2, 2005, U.S. EPA responded to Kentucky Heartwood, Case No. 1:05CV00535 (RBW). In brief, Kentucky's understanding of U.S. EPA position is that these state actions are not covered in the endangered species review provisions.

52)-**VII. THERE IS NO INDICATION THAT THE DIVISION CONSIDERED ALTERNATIVES TO PERMITTING A LARGE COAL PLANT**

The records we reviewed do not indicate that the Division considered whether or not energy efficiency, renewable energy, or a natural gas-fired power plant could individually, or in combination eliminate the need for a new, large coal-fired power plant. We urge the Division to conduct an analysis of whether these cleaner, safer, and more cost-effective options for meeting our energy needs.

The PSD program has three central features that advance its general purpose of preventing increases of air pollution that a state finds undesirable. These include the BACT requirements, the prevention of ambient air quality deterioration provisions, and a robust public participation and state decision-making process. Section 165(a) of the Act prohibits construction of major stationary sources in PSD areas unless an applicant demonstrates that these and other requirements have been met. 42 U.S.C. § 7475(a).

USEPA has provided a detailed explanation of the BACT provision:

> The technology-forcing component of the PSD program provides that proposed facilities are subject to the "best available control technology" for each pollutant subject to regulation under the Act that is emitted from such facilities. 42 U.S.C. § 7475(d)(4). Congress granted permitting authorities broad discretion to determine BACT in a manner consistent with the environmental protection goals of the PSD program, allowing considering of "energy, environmental, and economic impacts." Specifically, the legislative history demonstrates that Congress authorized the concerns of the community regarding the overall impact of the source on air quality to be factored into the BACT components of the PSD permitting decision.
>
> [W]hen an analysis of energy, economics, or environmental considerations indicates that the impact of a major facility could alter the character of that community, then the State could, after considering those impacts, reject the application or condition it within the desires of the State or local community. Flexibility and State judgment are the foundations of this policy.

See S. Rep. No. 127, 95th Cong., 1st Sess. 31 (1977) reprinted in 3 Senate Comm. on Environment and Public Works, 95th Cong., 2d Sess., A Legislative History of the Clean Air Act Amendments of 1977, at 1405 (1978).

Section 165(a)(2) establishes the obligation of a permitting agency to consider, and an opportunity for the public to comment on, alternatives to major new sources of air pollution. For attainment areas, section 165(a)(2) prohibits construction of a new major emitting facility unless "a public hearing has been held with opportunity for interested persons * * * to appear and submit written or oral presentations on the air quality impact of such source, alternatives thereto, control technology requirements, and other appropriate considerations." 42 U.S.C. § 7475(a) (emphasis added).

The CAA and the PSD regulations establish a robust and meaningful public participation framework that requires IEPA to consider "alternatives" (42 U.S.C. § 7475(a)) to major sources of air pollution and "a careful evaluation of the consequences of such a decision," indicating that alternatives actually be considered. 42 U.S.C. § 7470(5).

USEPA has taken the position repeatedly that energy efficiency, other alternatives, and the need of a project are all factors that can and must be considered by a PSD permitting authority if raised during the public comment process. In 1996 USEPA filed a brief in Ecoelectrica, 7 E.A.D. 56 (EAB 1997), in which it stated:

> Energy conservation is central to meaningful air pollution prevention initiatives, and energy conservation considerations are cognizable under the PSD program. Further the EAB has recognized the legal authority under the PSD program to consider alternatives to a proposed source in Hawaiian Commercial & Sugar Company, 4 EAD at 99-100, and Old Dominion Electric Cooperative, 3 EAD at 793-794. These precedents logically encompass the legal discretion to consider energy conservation as an alternative to a proposed source.

Response of EPA Region II and EPA Office of Air and Radiation to Mr. Arana's Petition for Review, Ecoelectrica LNG Import Terminal and Cogeneration Project, (Dec. 24, 1996). Although the Board did not require consideration of need in that case, the Board did not foreclose review when the state refuses to do so.

> [T]he Board did not mean to address the issue of whether, and under what circumstances, the Board could consider a challenge based on alternate means of meeting energy needs. Rather, as in Kentucky Utilities and as in this case, the Board merely meant to suggest that review under 40 C.F.R. § 124.19(a) was not warranted because the need for the power from a proposed facility would 'more appropriately' be addressed by the responsible State authority.

Ecoelectrica 7 E.A.D. at 74 n.25.
Gregory Foote wrote in his thoughtful article Considering Alternatives: The Case for Limiting CO2 Emissions From New Power Plants Through New Source Review that power plants warrant special scrutiny in the PSD permitting process:

> Because the function of any single plant typically is to add to a common pool of electricity supply, the threshold question of need should never be ignored in deciding whether to issue a permit. … Coal-fired plants in particular merit extra scrutiny because of their tremendous size, longevity, capital and operating costs, demands on fuel suppliers and transmission lines, and adverse environmental impacts. All these public policy concerns are best addressed by reading the CAA as providing no vested right to build a coal-fired plant in any form, and as requiring that every decision to do so only be made after careful consideration of each important aspect of the consequences of that decision. As discussed below, this reading is also the best one under the law.
>
> …
>
> The threshold question in considering any prospective new or modified electricity generating plan fired by fossil fuels is why the plant should be constructed at all: obviously, it is preferable from the air quality standpoint to rely on renewable energy and more efficient use of existing resources than construct any new fossil-fuel plant.

34 ELR 10642, 10657-58 (July 2004).

In sum, the Clean Air Act affords the Division significant authority to protect its State's air resources and it is not required to blindly issue permits for sources of air pollution that will have significant public health, economic, and environmental impacts for decades into the future.

Division Response:

The Division does not concur, and suggests that these are issues more appropriate for the Public Service Commission and the Siting Board, both of whom are reviewing the construction of this project.

With respect to Gregory Foote's article Considering Alternatives: The Case for Limiting CO_2 Emissions From New Power Plants Through New Source Review. *The article contains the following:*

> *Gregory B. Foote is Assistant General Counsel in the Air and Radiation Law Office at the U.S. Environmental Protection Agency (EPA). Since 1990, he has led a team of lawyers at U.S. EPA providing counseling and litigation support on a range of environmental issues. These include new source review, operating permits, visibility protection, enforcement and monitoring, nuclear waste disposal, and secondhand tobacco smoke. During 2003, he was a Faculty Visitor at the New Zealand Centre for Environmental Law, University of Auckland. He is presently detailed to the Center for International Environmental Law (CIEL) in Washington, D.C. The author would like to acknowledge the assistance of Monica Derbes Gibson, Acting Assistant General Counsel, EPA, and Donald Goldberg, Senior Attorney, CIEL, for reviewing a draft of this Article and making valuable suggestions.* ***The views expressed in this Article are solely those of the author and do not reflect the position of either EPA or CIEL. (Emphasis added)***

The article that he authored was not official U.S. EPA policy or interpretation, as indicated by the article itself and should only be given the same weight as any other professional article. Respectfully, the Division disagrees that authority exists that the commenter suggests, nor is the commenter familiar with aspects of Kentucky law and regulations, in particular KRS 224.20-125.

53)-**VIII. THE MODELING MUST CONSIDER PEAK NO_X LIMITS THAT MAY OCCUR**

It is not clear from the record that the maximum short-term NO_x emissions, i.e. the combination of emissions from Unit 1 and 2, were used in the modeling for ensuring compliance with the NAAQS and Class 1 requirements.

Division Response:

The NO_x NAAQS is an annual average; impacts on Class I visibility are based on a daily emission rate. The permit contains a daily limit on NO_x emissions.

54)-**IX. THE PEABODY THOROUGHBRED DECISION CONFIRMS MANY SHORTCOMINGS IN THE TRIMBLE DRAFT PERMIT**

Given the hearing examiner's recommendation in the Peabody Energy Thoroughbred matter dated August 9, 2005 (attachment G), we again respectfully request that the Trimble permit is re-noticed for public comment. Many of the issues petitioners raised in the Peabody matter successfully also apply in this Trimble proceeding and we request the opportunity to submit additional comments raised by the hearing examiner's decision.

Division Response:

The Division does not concur. EPPC Cabinet Secretary Wilcher has not ruled on the draft recommendations regarding the Thoroughbred permit made by the Office of Administrative Hearings. If a final determination of the Cabinet is made prior to the issuance of the final LG&E permit it will be given all due consideration.

Comments on the Louisville Gas & Electric Company's Trimble Co. Generating Station Draft Title V Air Quality Permit received verbally at the public hearing held on August 8, 2005

55)-**VISIBLE PLUME, ODOR**

Jill Mahoney, expressed concerns about the current emissions, in particular a blue haze that is characteristic of SO_3 emissions from the plant. Kelley Leach also expressed concerns about visible emissions and odor indicating SO_3 or ammonia. Steve Boldery and Gary Callis expressed similar concerns.

Division Response:

From the commentor's description and photographs presented at the hearing, there are indications of a visible plume being emitted from the existing unit. This permitting action is for the construction of Unit #2; concerns about existing units will be handled through the appropriate inspection and complaint procedures. The Division has received assurances from the company of their commitment to resolve this problem, and the Division will diligently follow these concerns until they are resolved. The Division has started a citizen's complaint entry in its TEMPO database, and will investigate these concerns. The Division will remain in contact with the commenter on the resolution of the problem.

56)-**COOLING TOWER**

Dudley Andrew asked about emissions from the cooling tower, if these emissions are included in the analysis.

Division Response:

The Cooling Tower is included in this permit. Emissions from the cooling tower will primarily be the results of dissolved solids that remain when fine droplets of the water remain after evaporation. In addition, LG&E has added the following

> *The chemicals used in the existing cooling tower water to maintain the system and minimize growth of bacteria, and other organics, are not regulated by EPA's risk management plan prevention provisions and OSHA's Process Safety Management program, and are not identified on EPA's list of hazardous air pollutants (HAPs). LG&E expects to use the same chemicals to maintain the proposed cooling tower when operational. Additionally, the new cooling tower will be equipped with 0.0005% drift eliminators which are more efficient at lowering the amount of drift out of the cooling tower.*

57)-**Sierra Club comments**

The majority of Sierra Club comments were submitted in written form. There were some remarks made at the public hearing that the Division does not believe were reflected in the written material submitted. Joan Lindop as a member of the Sierra Club made several comments on the need to construct the plant, that Kentucky was not enforcing the requirements of the Clean Air Act as well as other states.

Division Response:

The need to expand the plant is not in the purview of the Division. The Division is aware that Trimble Unit #2 is undergoing review by the Public Service Commission and the Siting Board.

A statement was also made that some states are doing better than Kentucky in the area of emissions. The Division disagrees with statement. First, all decisions of Best Achievable Control Technology are reviewed by U.S. EPA. Even in the unlikely event that a state agency would be remiss in its obligation to protect the health and welfare of its citizens, U.S. EPA has the authority to correct any obvious error. Secondly for unit #2, its emissions for NO_x, SO_2 *and PM are among the best nationally for any proposed coal fired EGU. The* NO_x *emission levels are lower than those proposed in recent applications and permits for coal gasification units.*

58)-**Group Comments:**

Letters were received from commenters objecting to the construction of the proposed facility. Concerns were raised regarding noise, emissions, haze, and odor. Questions were also raised about the necessity of construction of the facility.

Division Response:

The facility will be permitted to meet all applicable air quality standards and regulations. The question of need is beyond the purview of the permit.

CREDIBLE EVIDENCE:

This permit contains provisions which require that specific test methods, monitoring or recordkeeping be used as a demonstration of compliance with permit limits. On February 24, 1997, the U.S. EPA promulgated revisions to the following federal regulations: 40 CFR Part 51, Sec. 51.212; 40 CFR Part 52, Sec. 52.12; 40 CFR Part 52, Sec. 52.30; 40 CFR Part 60, Sec. 60.11 and 40 CFR Part 61, Sec. 61.12, that allow the use of credible evidence to establish compliance with applicable requirements. At the issuance of this permit, Kentucky has only adopted the provisions of 40 CFR Part 60, Sec. 60.11 and 40 CFR Part 61, Sec. 61.12 into its air quality regulations.